STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Power Agency	**:**	
	:	
Petition for Approval of its	**:**	**16-0453**
2017 Procurement Plan pursuant to	**:**	
Section 16-111.5(d)(4) of the	**:**	
Public Utilities Act.	**:**	

PROPOSED ORDER

November 14, 2016

Table of Contents

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Power Agency	:	
	:	
Petition for Approval of its	:	**16-0453**
2017 Procurement Plan pursuant to	:	
Section 16-111.5(d)(4) of the	:	
Public Utilities Act.	:	

PROPOSED ORDER

By the Commission:

I. INTRODUCTION

Section 16-111.5(d)(2) of the Public Utilities Act ("PUA") requires the Illinois Power Agency ("IPA") to prepare a power procurement plan ("Draft Plan"), which is to be posted on the IPA and Illinois Commerce Commission ("Commission") websites. 220 ILCS 5/16-111.5(d)(2). Comments on the Draft Plan were submitted to the IPA for its review. The PUA requires the IPA to make revisions to the Draft Plan based on the submitted comments, and then formally file a revised plan with the Commission.

On September 27, 2016, the IPA filed with Commission its 2017 Power Procurement Plan ("2017 Plan"), initiating this proceeding. Among other things, the purpose of the 2017 Plan is to secure electricity commodity and associated transmission services to meet the needs of eligible retail customers in the service areas of Commonwealth Edison Company ("ComEd"), Ameren Illinois Company d/b/a Ameren Illinois ("Ameren"), and MidAmerican Energy Company ("MidAmerican").

Section 16-111.5(d)(3) of the PUA provides that, within five days of the filing of a procurement plan, any objections to it must be filed with the Commission. The same subsection also provides that the Commission shall enter an order approving or modifying the procurement plan within 90 days after the filing of the plan. 220 ILCS 5/16-111.5(d)(3). The 2017 Plan was filed on September 27, 2016; thus, the deadline is December 27, 2016. Pursuant to Section 16-111.5(d)(4) of the PUA, the Commission shall approve the procurement plan, including the load forecasts used in the plan, "if the Commission determines that it will ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability." 220 ILCS 5/16-111.5(d)(4).

Section 16-111.5(e) specifies the major components to be included in the procurement process. Section 16-111.5(e)(4) provides that a procurement administrator shall design and issue a request for proposals ("RFP") to supply electricity in accordance with each utility's procurement plan, as approved by the Commission. The RFPs shall set forth a procedure for sealed, binding commitment bidding with pay-as-bid settlement, and provision for the selection of bids on the basis of price. Section 16-111.5(f) requires confidential reports to be submitted to the Commission by the procurement administrator and procurement monitor after the opening of the sealed bids. Subsection (f) further provides that the Commission shall review the confidential reports submitted by the procurement administrator and procurement monitor, and it shall accept or reject the recommendations of the procurement administrator within two business days after receipt of the reports.

II. PROCEDURAL HISTORY

Following the filing of the 2017 Plan, the following entities were granted leave to intervene: Citizens Utility Board ("CUB"); the Renewables Suppliers; Environmental Law & Policy Center ("ELPC"); ComEd; MidAmerican; Ameren; Natural Resources Defense Council ("NRDC"); Retail Energy Supply Association ("RESA"); the Board of Trustees of the University of Illinois on behalf of the Energy Resources Center at the University of Illinois at Chicago ("ERC"); and the Illinois Solar Energy Association ("ISEA"). The Illinois Attorney General's Office on behalf of the People of the State of Illinois ("AG") filed an appearance in this docket.

On October 3, 2016, Objections and Comments to the Plan ("Cmnts.") were filed by Ameren; ComEd; the Renewables Suppliers; MidAmerican; ELPC; the AG; NRDC; and Staff of the Commission ("Staff"). Parties were notified that, pursuant to Section 16-111.5(d)(3) of the PUA, no hearing in this matter was determined to be necessary.

On October 20, 2016, the Renewables Suppliers filed a Response to the Objections. Pursuant to the schedule issued by the Administrative Law Judge, Responses to Objections ("Resp.") were filed on October 21, 2016 by the IPA; the AG; Staff; ComEd; Ameren; ELPC; MidAmerican; NRDC; and ERC. ISEA served its Comments on October 21, 2016 and filed them on October 27, 2106. Thereafter, Replies to Responses ("Rep.") were filed by the AG, the IPA, Ameren, the Renewables Suppliers, ELPC, ComEd, NRDC, and Staff on October 31, 2015.

The Proposed Order was served on the parties on November 14, 2016.

Section III of the Order contains a brief summary of the uncontested portions of the 2017 Plan as well as the IPA's Action Plan for the Commission. Sections IV and V of the Order discuss the contested issues in this proceeding, those surrounding Sections 8 and 9 of the 2017 Plan.

III. OVERVIEW OF THE 2017 PLAN

A. Introduction

This is the ninth electricity and renewable resource procurement plan prepared by the IPA under the authority granted to it under the Illinois Power Agency Act (20 ILCS 3855/1-1 *et seq.*) ("IPA Act") and the PUA. The IPA states that its 2017 Plan addresses the provision of electricity and renewable resource supply for the "eligible retail customers" of Ameren, MidAmerican and ComEd as defined in Section 16-111.5(a) of the

PUA. 220 ILCS 5/16-111.5(a). For Ameren and ComEd, "eligible retail customers" are generally residential and small commercial fixed-price customers who have not chosen service from an alternate supplier. MidAmerican initially participated in the 2016 IPA Procurement Plan ("2016 Plan") and again elects to have the IPA procure power and energy for a portion of its eligible Illinois customers through the 2017 Plan. For MidAmerican, "eligible retail customers" include residential, commercial industrial, street lighting, and public authority customers that purchase power and energy from MidAmerican under fixed-price bundled service tariffs. 2017 Plan at 1.

The 2016 Plan, approved by the Commission in Docket No. 15-0541, called for the energy and renewable resources requirements for Ameren, ComEd, and MidAmerican to be procured by the IPA through two block energy procurements (spring and fall), a spring renewables procurement, and an early summer distributed generation procurement. *See generally Illinois Power Agency*, Docket No. 15-0541, Order (Dec. 16, 2015) ("*2016 Plan Docket*"). In addition, the 2016 Plan included a capacity procurement for Ameren, which was held as a fall 2016 procurement event. The 2016 Plan also called for a minor change to the energy hedging strategy to bring the hedging level for October 2016 to 75% of average load at the time of the spring procurement event and to 100% in the fall procurement event. For the 2017 Plan, the IPA recommends a continuation of the energy procurement strategies proposed in the 2016 Procurement Plan. 2017 Plan at 1.

The 2017 Plan considers a 5-year planning horizon that begins with the 2017-2018 delivery year and lasts through the 2021-2022 delivery year. At its core, the 2017 Plan consists of three pieces: 1) a forecast of how much energy (and in some cases capacity) is required by eligible retail customers; 2) the supply currently under contract; and 3) what type and how much supply must be procured to meet load requirements and to satisfy all other legal requirements associated therewith (such as renewable/clean coal purchase requirements or mandates from previous Commission Orders). 2017 Plan at 8.

The 2017 Plan must contain an hourly load analysis, which includes: multi-year historical analysis of hourly loads; switching trends and competitive retail market analysis; known or projected changes to future loads; and growth forecasts by customer class. In addition, the 2017 Plan must analyze the impact of demand side and renewable energy initiatives, including the impact of demand response programs and energy efficiency programs, both current and projected. Based on the hourly load analysis, the 2017 Plan must detail the IPA's plan for meeting the expected load requirements that will not be met through pre-existing contracts. *See* 220 ILCS 5/16-111.5(b)(1)(i)-(iv), (b)(2) and (b)(3); 2017 Plan at 8.

Overall, the 2017 Plan defines the different Illinois retail customer classes for which supply is being purchased, and includes monthly forecasted system supply requirements, including expected minimum, maximum, and average values for the planning period. It also includes the proposed mix and selection of standard wholesale products for which contracts will be executed during the next year that separately, or in combination, will meet the portion of the load requirements not met through pre-existing contracts. In the case of MidAmerican, it includes allocations to eligible Illinois customers of energy and capacity from MidAmerican-owned generating resources. The 2017 Plan further details the proposed term structures for each wholesale product type included in the portfolio of products. 2017 Plan at 8-9.

The 2017 Plan assesses the price risk, load uncertainty, and other factors associated with the proposed portfolio measures. Those factors include contract terms, time frames for security products or services, fuel costs, weather patterns, transmission costs, market conditions, and the governmental regulatory environment. For those portfolio measures that are identified as having significant price risk, the 2017 Plan identifies alternatives to those measures. The 2017 Plan includes the proposed procedures for balancing loads, including the process for hourly load balancing of supply and demand and the criteria for portfolio re-balancing in the event of significant shifts in load. Finally, it includes renewable resource and demand-response products. 2017 Plan at 9.

The 2017 Plan proposes to continue using the risk management and procurement strategy that the IPA has historically utilized: hedging load by procuring on and off-peak blocks of forward energy in a three-year laddered approach. The IPA continues to recommend the procurement of standard energy in blocks of 25 megawatts ("MW"). The risk management strategy also continues to bifurcate the first delivery year into periods with different hedging levels—with June hedged at 100% of average load, July and August hedged to 106% of average on-peak load and 100% of average off-peak load, fall hedged to 100% of average load, and the balance of the year hedged to 75% of average load at the time of the spring procurement event. The IPA also recommends that the Commission approve a fall energy procurement event to bring the hedging level for the balance of the first delivery year (October through May) to the fully hedged level (100% of load). Consistent with other recent procurement plans, the IPA also recommends hedging 50% of the expected load for the second delivery year, and 25% of the expected load for the third delivery year. The IPA recommends the procurement of half of these volumes in the spring 2017 procurement event and the balance in the fall 2017 procurement event. 2017 Plan at 1-2.

Additionally, for Ameren's 2018-2019 planning year, the IPA recommends purchasing 75% of its forecasted capacity requirements in bilateral transactions and 25% from the Midcontinent Independent System Operator ("MISO") Planning Resource Auction ("PRA"). For Ameren's capacity requirements, the IPA will defer a decision for the 2019-2020 planning year and beyond until next year's plan. For ComEd, consistent with the strategy adopted in prior plans, the IPA proposes that forecast capacity requirements be secured by ComEd through the PJM Interconnection ("PJM") Reliability Pricing Model and Capacity Performance processes. For MidAmerican, consistent with the approach taken in the 2016 Plan, the IPA recommends that its forecast capacity shortfall be secured by MidAmerican through the annual MISO PRA. Aside from these proposals, the IPA recommends that capacity, ancillary services, load balancing services, and transmission services be purchased by Ameren and MidAmerican from the MISO marketplace and by ComEd from PJM's. 2017 Plan at 2.

B. Action Plan

In this plan, the IPA recommends the following items for Commission action:

1. Approve the base case load forecasts of ComEd, Ameren, and MidAmerican as submitted in July 2016.

2. Approve two energy procurement events scheduled for spring 2017 and fall 2017. The energy amounts to be procured in the spring will be based on the updated March 15, 2017 load forecasts developed by Ameren, MidAmerican, and ComEd, in accordance with the hedging levels stated in the 2017 Plan, and as approved by the Commission. The energy (and capacity for Ameren) amounts to be procured in the fall will be based on the July 15, 2017 updated base load forecasts developed by Ameren, MidAmerican, and ComEd, in accordance with the hedging levels stated in the 2017 Plan, and as approved by the Commission.

3. The March 15, 2017 and the July 15, 2017 forecast updates provided by the utilities to be used to implement the 2017 Plan will be pre-approved by the Commission as part of the approval of this Plan, subject to the review and consensus of the IPA, Staff, the Procurement Monitor, and the applicable utility. In the event that the parties do not reach consensus on an updated load forecast required in Item 2 above, then the most recent consensus load forecast will be used for the applicable procurement event. If the IPA, Staff, Procurement Monitor and applicable utility are unable to reach consensus on either of the updated load forecasts required in Item 2 above, then the July 2016 load forecast will be used for the applicable procurement event.

4. Approve procurement by ComEd, Ameren, and MidAmerican of capacity, network transmission service and ancillary services from their respective regional transmission organization ("RTO").

5. Approve a fall 2017 capacity procurement for Ameren.

6. Approve pro-rata curtailment of ComEd and/or Ameren's 2010 long-term power purchase agreements ("LTPPAs") for renewable energy in the unlikely event that the updated March 2017 load forecast indicates that such a curtailment is necessary. This forecast will form the basis for pro-rata curtailment of long term renewable contracts assuming consensus is reached among the parties identified in Item 3 above. Otherwise, the July 2016 forecast will form the basis for curtailment.

7. Approve a spring 2017 procurement of renewable energy credits ("RECs") using the Renewable Resources Budget ("RRB") for the prompt delivery year to allow the utilities to meet their renewable portfolio standard ("RPS") requirements other than for distributed generation for Ameren and ComEd. The volume for the procurement will be determined based upon the "Remaining Target" quantities resulting from the utilities' March 2017 load forecasts and limited to the funds available according to the utilities' updated renewable resource budgets.

8. Approve two procurements of distributed generation ("DG") RECs ("DG RECs") using the RRB for MidAmerican, and using already collected hourly alternative compliance payments ("ACP") funds for Ameren and ComEd, minus the total dollar value committed from prior distributed generation REC contracts. For Ameren and ComEd, the budget will also reflect any hourly

ACP funds committed to the purchase of curtailed RECs stemming from the 2010 LTPPAs.

9. Approve specific consensus items from the 2016 energy efficiency stakeholder workshops related to the implementation of Section 16-111.5B of the PUA that are set forth in Section 9.3.

10. Approve the Section 16-111.5B incremental energy efficiency programs identified in Chapter 9.

2017 Plan at 5-6.

C. Load Forecasts

Load forecasts are addressed in Section 3 of the 2017 Plan. The load forecasts are developed by the utilities, but the IPA reviews and evaluates the load forecasts to ensure they are sufficient for the purpose of procurement planning. The Commission is required to approve the 2017 Plan, including the forecasts on which it is based, before the 2017 Plan can be implemented. 2017 Plan at 18.

The 2017 Plan states that Ameren provides a base case and two complete excursion cases: a low forecast and a high forecast. Each excursion case addresses three different uncertainties that simultaneously move in the same direction: macroeconomics, weather, and switching. This means, for example, that a high load case should represent the combination of stronger-than-expected economic growth (which increases load), extreme weather (which increases load) and a reduced level of switching (which increases the "eligible" fraction of retail load, that is, the fraction for which the utility retains the supply obligation). Similarly, a low load case should represent the combination of weaker-than-expected economic growth, mild weather and an increase level of switching. 2017 Plan at 21.

The IPA reports that like Ameren, ComEd provides a base case load forecast and two excursion cases: a low-case forecast and a high-case forecast. Each excursion case addresses three different uncertainties, simultaneously moving in the same direction: macroeconomics, weather, and switching. 2017 Plan at 30. ComEd did not supply its forecasts for medium and large commercial and industrial customers, whose service has been deemed to be competitive and who therefore cannot be eligible retail customers. 2017 Plan at 28.

With respect to MidAmerican's load forecast, MidAmerican provided a base-case load forecast and two excursion cases: a low-case forecast and a high-case forecast. The required low and high hourly load forecast scenarios were created by taking the 95% confidence interval around each class-level's sales, customer and use per customer forecast and the 95% confidence interval around the non-coincident gross peak demand forecast. The load forecasting software used by MidAmerican provided the upper and lower bounds of a 95% confidence interval around each monthly forecast value. This software feature allowed the construction of upper and lower bound forecasts for the residential, commercial, industrial and public authority sales forecasts. The street lighting sales forecast was multiplied by 0.99 and 1.01 to generate, respectively, a lower and upper bound street lighting sales forecast. 2017 Plan at 37.

According to the IPA, it has procured power for the utilities to meet a monthly forecast of the average hourly load in each of the on-peak and off-peak periods. The IPA has addressed the volatility in power prices by "laddering" its purchases: hedging a fraction of the forecast two years ahead, another fraction one year ahead, and a third fraction shortly before the beginning of the delivery year. Even if pricing two years ahead were extremely advantageous, the IPA does not purchase its entire forecast that far ahead because the forecast is itself uncertain. 2017 Plan at 40.

Furthermore, even if the Agency could perfectly forecast the average hourly load in each period, and perfectly hedge that forecast, it would still be exposed to power cost risk. This is because energy in one hour is not a perfect substitute for energy in another hour because the hourly spot prices differ. 2017 Plan at 40.

The 2017 Plan explains the many factors that can cause load forecast uncertainty. These factors include: overall load growth uncertainty, the weather, load profiles, municipal aggregation and individual switching, hourly billed customers, energy efficiency, demand response and emerging technologies. *See* 2017 Plan at 41-46.

The IPA recommends adoption of the Ameren, ComEd, and MidAmerican base case load forecasts. Ameren's and ComEd's forecasts include already approved energy efficiency programs. MidAmerican's forecast includes verified energy efficiency program impacts as well. The IPA also recommends that the Commission approve the additional incremental energy efficiency programs and measures as presented in Chapter 9 of the 2017 Plan. The IPA says the March 2017 load forecasts should also reflect those newly approved programs. 2017 Plan at 45.

D. Existing Resource Portfolio and Supply Gap

Starting with the 2014 Procurement Plan, the IPA has purchased energy supply in standard 25MW on-peak and off-peak blocks. These purchases are driven by the supply requirements outlined in the current year procurement plan and are executed through a competitive procurement process administered by the IPA's Procurement Administrator. The 2017 Plan explains that this procurement process is monitored for the Commission by the Commission-retained Procurement Monitor. 2017 Plan at 47.

In addition to purchasing energy block contracts in the forward markets, Ameren, MidAmerican, and ComEd rely on the operation of their RTOs (MISO and PJM) to balance their loads and consequently may incur additional costs or credits. According to the 2017 Plan, purchased energy blocks may not perfectly cover the load, therefore triggering the need for spot energy purchases or sales from or to the RTO. The IPA's procurement plans are based on a supply strategy designed, among other things, to balance price risk and cost. The underlying principle of this supply strategy is to procure energy products that will cover all or most of the near-term load requirements and then gradually decrease the amount of energy purchased relative to load for the following years. 2017 Plan at 47.

Because of the uncertainty in the amount of eligible retail customer load in future years, the IPA has not purchased energy beyond a 3-year horizon, except in a few circumstances. These include: 1) a 20-year bundled REC and energy purchase (the LTPPAs), made by Ameren and ComEd, pursuant to the Commission's Order in Docket No. 09-0373. *Illinois Power Agency*, Docket No. 09-0373, Order (Dec. 28, 2009); and 2) the February 2012 “Rate Stability” procurements mandated by Public Act 97-0616 for block energy products covering the period June 2013 through December 2017. According to the 2017 Plan, under the current utility load forecasts, which contemplate relatively flat customer switching, curtailment of the Ameren and ComEd LTPPAs is unlikely for the 2017-2018 delivery year. MidAmerican is not covered by either LTPPAs or Rate Stability procurements. 2017 Plan at 47.

The 2017 Plan states that Ameren’s existing supply portfolio, including long-term renewable resource contracts, is not sufficient to cover the projected load for the 2017-2018 delivery year. Additional energy supply will be required for the entire 5-year planning period. Under the base case load forecast scenario, the average supply gap for peak hours of the 2017-2018 delivery year is estimated to be 421 MW, the peak period average supply gap for the 2018-2019 delivery year is estimated to be 629 MW, and the average peak period supply gap for the 2019-2020 delivery year is estimated to be 772 MW. While the planning period is five years, the IPA’s hedging strategy is focused on procuring electricity supplies for the immediate three delivery years. 2017 Plan at 48.

ComEd’s current energy resources, the 2017 Plan explains, will not cover eligible retail customer load starting in June 2017. The average supply gap during peak hours for the 2017-2018 delivery year under the base case load forecast is estimated to be 1,505 MW. The average supply gap during peak hours for the 2018-2019 and 2019-2020 delivery years is estimated to be 2,251 MW and 2,856 MW respectively. 2017 Plan at 49.

MidAmerican has requested that the IPA procure electricity for the incremental load that is not forecasted to be supplied in Illinois by MidAmerican’s Illinois jurisdictional generation. MidAmerican’s existing eligible retail customer load is served by an allocation of capacity from MidAmerican’s resources (“Illinois Historical Resources”). In reviewing the load forecast and resource portfolio information supplied by MidAmerican for the 2017 Plan, the IPA notes that MidAmerican “dispatches” its Illinois Historical Resources whenever the expected cost to generate electricity is less than the expected cost of acquiring it in the market. The maximum generation output during each hour is then capped at the maximum of the generation capacity or the forecasted demand level, whichever is lower. The IPA recommends removing this cap for the 2017 Plan. The 2017 Plan explains that removing the cap represents an incremental improvement and would entail no effort to implement. 2017 Plan at 49-50.

Due to current and anticipated MidAmerican generating unit retirements, MidAmerican will rely to a greater extent on the IPA procurements to make up the difference from generation allocated to serve its Illinois eligible retail customer load. The average supply gap during peak hours for the 2017-2018 delivery year under the base case load forecast is estimated to be 80 MW. The average supply gap during peak hours for the 2018-2019 delivery year is 95 MW and for the 2019-2020 delivery year the supply gap is 79 MW. 2017 Plan at 50.

E. MISO and PJM Resource Adequacy Outlook and Uncertainty

The 2017 Plan explains that as a result of retail choice in Illinois, the resource adequacy challenge (the load and resource balance) can be summarized as a function of determining what level of resources to purchase and from which markets. However, for the Illinois market to function properly, the RTO markets and operations (e.g., MISO and PJM) must provide sufficient resources to satisfy the load requirements for all customers reliably. 2017 Plan at 53.

The IPA reports that, over the planning horizon, PJM will maintain adequate resources to meet the collective needs of customers in those regions. PJM is projected to have sufficient resources to meet load plus required reserve margins for the Delivery Years 2016-2017 to 2021-2022, with projected reserve margins above the 15.5% target reserve margin in 2016-2017 and the 15.7% target reserve margin for the remaining Delivery Years. For the 2016-2017 Delivery Year, the reserve margin is approximately 10% above the target reserve margin, peaks at approximately 16% above the target reserve margin in 2018-2019 and then drops to approximately 12% above the target reserve margin for the 2021-2022 Planning Year. 2017 Plan at 53.

MISO, on the other hand, could be short resources starting in the 2021-2022 timeframe. On a region-wide basis MISO is expected to have sufficient resources to meet load plus required reserve margin for the Planning Years 2016-2017 to 2020-2021 with projected reserve margins above the 14.3% target reserve margin. However, in 2021-2022 MISO is projected to have insufficient resources to meet load plus required reserve margin. For the 2016-2017 Planning Year, the reserve margin is approximately 2% above the target reserve margin, dropping to approximately 0.4% above the target reserve margin for the 2020-2021 Planning Year. 2017 Plan at 54. MISO projects that reserve margins will continue to tighten over the next five years, approaching the target reserve margin. Operating at the reserve margin creates a new operating reality for MISO members where the use of all resources on the system and emergency operating procedures are more likely. This could lead to a projected dependency in the use of load-modifying resources such as behind-the-meter generation and demand response. 2017 Plan at 55.

F. Managing Supply Risks

The IPA Act lists the priorities applicable to the IPA's portfolio design, which are "to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability." 20 ILCS 3855/1-20(a)(1). The 2017 Plan notes that at the same time, the legislature recognized that achievement of these priorities requires a careful balancing of risks and costs, when it required that the Procurement Plan include:

> an assessment of the price risk, load uncertainty, and other factors that are associated with the proposed procurement plan; this assessment, to the extent possible, shall include an analysis of the following factors: contract terms, time frames for securing products or services, fuel costs, weather patterns, transmission costs, market conditions, and the governmental regulatory environment; the proposed procurement plan shall also identify alternatives for those portfolio measures that are identified as having significant price risk.

220 ILCS 5/16-111.5(b)(3)(vi); 2017 Plan at 65.

Chapter 6 of the 2017 Plan discusses and assesses risks in the supply portfolio, as well as tools and strategies for mitigating them. The IPA notes that developing a risk management strategy requires knowledge of the risk factors associated with energy procurement and delivery, and of the tools available to manage those risks. Section 6.1 describes the relevant risk factors. Sections 6.2 and 6.3 describe the types of contracts and hedges that can be used to manage supply risk. Those products may be thought of as being used to build a supply portfolio. Section 6.4 addresses the complementary issue of reducing or re-balancing the supply portfolio when needed, and the legal, regulatory and policy issues that may arise if utilities have to do so by selling previously purchased hedges over-the-counter. 2017 Plan at 65.

Section 6.6.2 of the 2017 Plan addresses the cost and uncertainty impacts of these risk factors. The 2017 Plan explains that risk is often taken to mean the amount by which costs differ from initial estimates. Utility energy pricing in Illinois for Ameren and ComEd customers is based on estimates and cost differences are trued up after the fact through the Purchased Electricity Adjustment ("PEA"). *See* 220 ILCS 5/16-111.5(l). This policy is manifest through riders filed by each utility – ComEd's Rider PE (Purchased Electricity), and Ameren's Rider PER (Purchased Electricity Recovery). Prior to the 2016-2017 delivery year, MidAmerican provided power and energy to its eligible Illinois customers from MidAmerican owned generation. The energy pricing for MidAmerican customers in Illinois has been recovered through base rates regulated by the Commission. Starting with the 2016-2017 delivery year, MidAmerican pricing for its Illinois customers also includes the energy obtained in IPA procurements, and that will be reflected through a cost recovery process similar to what is used by Ameren and ComEd. Section 6.5 of the 2017 Plan provides a historical summary of the Ameren and ComEd PEA rates as a guide to the historical impact of risk factors. Section 6.5 also addresses the changes in MidAmerican pricing that reflect the costs of participating in the IPA procurements. Section 6.6 discusses the IPA's historical approach to risk and portfolio management. Finally, Section 6.7 addresses demand management. 2017 Plan at 65.

G. Resource Choices

Chapter 7 of the 2017 Plan includes recommendations for the resources to be procured for the forecast horizon covered by the 2017 Plan. These include: 1) energy; 2) capacity; 3) transmission and ancillary services; 4) demand response; and 5) clean coal. Procurement of renewable resources, including wind, solar and DG is considered separately in Chapter 8 of the 2017 Plan. Procurement of incremental energy efficiency programs and measures is considered separately in Chapter 9.

The IPA procurement strategy involves the procurement of hedges to meet a portion of the hedging requirements over a three-year period and includes two procurement events in which the July and August peak requirements will be hedged at 106%, while the remaining peak and off-peak requirements will be hedged at 100%. In the spring procurement event, 106% of the July and August expected peak, 100% of the July and August off-peak, 100% of the June and September peak and off-peak, and 75% of the October through May peak and off-peak requirements for the 2017-2018 delivery year will be targeted for procurement. The fall procurement event will bring the targeted hedge levels to 100% for October through May of the 2017-2018 delivery year. A portion of the targeted hedge levels for the 2018-2019 and the 2019-2020 delivery years of 50% and 25%, respectively, will be acquired in the spring and fall procurement events. 2017 Plan at 75.

Prior procurement plans, including the 2016 Plan, have recommended that ComEd obtain its capacity needs through the PJM-administered capacity market. For the 2017 Plan, the IPA recommends that ComEd continue to obtain its capacity needs from the PJM-administered capacity market. 2017 Plan at 83.

For Ameren, the 2015 and 2016 Plans recommended procurement of at least a portion of the Ameren capacity needs through bilateral capacity purchases with the remainder of the capacity needs procured from the MISO PRA. The 2017 Plan states that given the current uncertainty around the design of the MISO PRA and the resulting effects of any design changes, the IPA recommends deferring any decision regarding the capacity procurement strategy for the 2019-2020 planning year and beyond until next year's Plan. 2017 Plan at 83.

The IPA proposes the following capacity procurement strategy: 1) as approved under the 2016 Plan, for the 2017-2018 Planning Year, 75% of the Ameren Capacity would be procured through an RFP in the fall of 2016, with the remaining 25% being procured in the MISO PRA; 2) as approved under the 2016 Plan, for the 2018-2019 Planning Year, 25% of the Ameren Capacity would be procured through an RFP in the fall of 2016, 50% will be procured through an RFP in the fall of 2017 and the remaining 25% will be procured in the MISO PRA; and 3) for the 2019-2020 Planning Year, the decision will be deferred until next year's Plan. 2017 Plan at 83.

MidAmerican has elected to procure power and energy through the IPA procurement process for the incremental amount of load that is not currently served or forecasted to be served in Illinois by MidAmerican-owned Illinois jurisdictional generation. The IPA notes that the magnitude of the proposed capacity procurements for MidAmerican is small relative to its capacity requirements. Also, consistent with the discussion regarding the procurement strategy for ComEd, the IPA recommends that MidAmerican obtain 100% of its forecast capacity shortfall from the MISO PRA capacity market. 2017 Plan at 83.

Ameren, MidAmerican, and ComEd purchase their transmission and ancillary services (which include energy balancing) from their respective RTOs - Ameren and MidAmerican from MISO and ComEd from PJM. The utilities also manage their Financial Transmission Rights and Auction Revenue Rights processes in their respective RTOs, consistent with Commission orders in prior plans. The 2017 Plan states that the IPA is not aware of any justification or reason to alter these practices and therefore recommends they remain unchanged. 2017 Plan at 85.

The 2017 Plan does not propose any procurement of demand response programs from eligible retail customers in the 2017-2018 delivery year. It explains that under current market and regulatory conditions, the IPA believes that a new demand response procurement by the IPA could not meet the standards set forth in Section 16-111.5(b)(3) of the PUA. The 2017 Plan states that reasons for this include the statutory requirement that demand response under this provision must come from "eligible retail customers." Section 16-111.5B of the PUA explicitly extends energy efficiency program participation to potentially "eligible retail customers" to accommodate the challenges created by customer switching. In contrast, Section 16-111.5(b)(3)(ii)(A) contains no such provision, and there may be no feasible way to ensure that only eligible retail customers participate. This challenge significantly reduces the likelihood that any demand response procurement would be cost-effective. Further, the 2017 Plan states that there could be challenges in satisfying the demand-response requirements of the RTO market in which the utility's service territory is located, and providing for customers' participation in the stream of benefits produced by the demand-response products. Fortunately for customers (including both eligible retail customers and those who have switched suppliers or take hourly priced service), the Peak Time Rebate (or Savings) programs as offered by Ameren and ComEd create value through reduction in capacity charges. The technologies utilized for capacity reductions also have the potential to provide longer term demand response capability that could operate over more peak hours than those used for calculations of capacity obligations. 2017 Plan at 86.

With respect to clean coal, the 2017 Plan states that the IPA Act contains an aspirational goal that cost-effective clean coal resources will account for 25% of the electricity used in Illinois by January 1, 2025. 20 ILCS 3855/1-75(d). As a part of the goal, the Plan must also include electricity generated from clean coal facilities. While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act, Section 1-75(d) describes two special cases: the "initial clean coal facility" and "electricity generated by power plants that were previously owned by Illinois utilities and that have been or will be converted into clean coal facilities ("retrofit clean coal facility"). 20 ILCS 3855/1-75(d)(5). The 2017 Plan states that the IPA is unaware of any facility meeting the definition of an "initial clean coal facility" that has announced plans to begin operations within the next five years. 2017 Plan at 86-87.

H. Procurement Process Design

The 2017 Plan explains that the procedural requirements for the procurement process are detailed in Section 16-111.5 of the PUA. The Procurement Administrator, retained by the IPA in accordance with 20 ILCS 3855/1-75(a)(2), conducts the competitive procurement events on behalf of the IPA. The costs of the Procurement Administrator incurred by the IPA are recovered from the bidders and suppliers that participate in the competitive solicitations, through both Bid Participation Fees and Supplier Fees which are assessed by the IPA. The eligible retail customers for each of the participating utilities ultimately incur these costs as it is assumed that suppliers' bid prices reflect a recovery of these fees. As required by the PUA and in order to operate in the best interests of consumers, the IPA and the Procurement Administrator review the procurement process each year in order to identify potential improvements. 2017 Plan at 130.

For the last several procurements, the Bid Participation Fee has been nominal ($500), which means that the bulk of the costs of the procurement event (which are typically several hundred thousand dollars) are recovered from winning bidders through Supplier Fees. There are risks for the IPA in recovering its costs with this fee structure. The IPA recommends that the approach used in the procurement events since 2014 be continued. The IPA explains that this approach is for the energy, capacity and non-DG REC contracts to maintain the condition in the utility pre-bid letter of credit allowing the utility to draw if the Supplier Fees are not paid by a date certain. Likewise, as used in the recent procurement events, there will also be an agreement between the IPA and each utility on how funds would flow back to the IPA for payment of the Supplier Fees under this circumstance. 2017 Plan at 132.

With respect to contract forms, the IPA believes that the forms have now become largely standardized and should remain acceptable to future potential bidders. As was the case with the 2014, 2015 and 2016 procurement events, the process to receive comments from potential bidders can be restricted to changes to the forms, thus reducing Procurement Administrator time and billable hours, while shortening the critical path time needed to conduct a procurement event. 2017 Plan at 131. The IPA also understands that markets are dynamic and periodic review of contract terms is necessary to ensure proper protection for the utilities, utility customers and suppliers. The IPA therefore recommends that the last used forms, namely the energy, capacity and RPS contracts used in the 2016 procurement events be the starting point for the contracts used in the energy, capacity, and REC procurements associated with the 2017 Plan. The IPA also recommends that the IPA, Staff, the Procurement Administrator, the Procurement Monitor, and utilities undertake a joint review of such contracts in order to identify what terms, if any, need to be modified. 2017 Plan at 131-132.

The IPA further recommends that procurement events be held in the spring and fall of 2017 for purchase of energy blocks, capacity and RECs under the 2017 Plan, and two procurements of DG REC be held at dates to be determined. The IPA recommends that the fall procurement event include the procurement of standard energy products for MidAmerican, Ameren and ComEd as well as a portion of the Ameren capacity requirements. 2017 Plan at 133.

Finally, the IPA discusses informal hearings. Section 16-111.5(o) of the PUA states:

> On or before June 1 of each year, the Commission shall hold an informal hearing for the purpose of receiving comments on the prior year's procurement process and any recommendations for change.

220 ILCS 5/16-111.5(o). On May 23, 2016, Staff posted a public notice of an informal hearing for the purpose of receiving comments regarding the procurement process for the procurement events that were held during the summer and fall of 2015 and the spring of 2016. The IPA states that the comments received in the informal hearings are available on the Commission's website. 2017 Plan at 134.

IV. SECTION 8 RENEWABLE RESOURCES AVAILABILITY AND PROCUREMENT

Chapter 8 of the 2017 Plan focuses on the procurement of renewable resources on behalf of eligible retail customers and provides informational guidance on use of the Renewable Energy Resources Fund ("RERF"), which contains ACP payments made by alternative retail electric suppliers ("ARES") as part of their RPS compliance obligations. Renewable energy resource procurement on behalf of eligible retail customers is subject to targets for purchase volumes (represented as a percentage of eligible retail customer load) found in Section 1-75(c)(1) of the IPA Act and capped by the 2.015% upper limit on customer bill impacts found in Section 1-75(c)(2)(E) of the IPA Act. The cap on the available budget for each utility is based on the utility's most recent load forecast. 2017 Plan at 88.

Consistent with past years, the 2017 Plan calls for REC procurements to meet the RPS targets and technology-specific sub-targets found in Section 1-75(c)(1) of the IPA Act for Ameren, ComEd, and MidAmerican, with the budgets for those procurements capped by the rate impact cap described in Section 1-75(c)(2)(E). 2017 Plan at 88.

MidAmerican's involvement in the 2016 Plan raised questions about how to calculate the renewable resource target applicable to MidAmerican. In approving the 2016 Plan, the Commission determined that the renewable resources targets for MidAmerican should only relate to that portion of the total supply procured for MidAmerican's jurisdictional eligible retail customers that was included in the 2016 Plan pursuant to Section 16.111.5 of the PUA and Section 1-75(c) of the IPA Act. *2016 Plan Docket*, Order at 133-134. The 2017 Plan's procurement targets for MidAmerican thus reflect the Commission's decision in the *2016 Plan Docket*. 2017 Plan at 88.

Section 1-75(c)(1) of the IPA Act requires the procurement of at least a minimum percentage of "each utility's total supply to serve the load of eligible retail customers" from "cost-effective renewable energy resources." 20 ILCS 3855/1-75(c)(1). Under that provision, specified target percentages of renewable energy resources are required to be procured for each participating utility. The overall renewable energy resources obligation for the utilities in the 2017-2018 delivery year is 13% of the total supply to meet the load of eligible retail customers by June 1, 2017. This obligation increases by at least 1.5% each year thereafter to at least 25% by June 1, 2025. The IPA Act also sets sub-targets for specific resource generating technology types: 75% of the resources procurement shall be generated by wind, 6% for photovoltaics, and 1% must come from DG which can be used to meet the PV and wind requirements. 20 ILCS 3855/1-75(c)(1). 2017 Plan at 89.

For the 2017-2018 delivery year, existing resources under contract for Ameren, ComEd and MidAmerican are not sufficient to meet the utilities' renewable resource procurement targets. More specifically, Ameren's 2017-2018 targets for overall RECs and wind RECs have been exceeded through prior REC procurements (specifically, the LTPPAs), however Ameren is short of its solar and DG REC sub-targets. ComEd and MidAmerican are both short of their overall RECs target as well as their wind, solar and DG RECs sub-targets. 2017 Plan at 90.

To achieve statutory compliance, the IPA recommends spring 2017 procurement of RECs to meet the ComEd and MidAmerican overall REC targets, and to meet each utility's unmet technology-specific sub-targets (solar for all three utilities, wind for ComEd and MidAmerican) for the 2017-2018 delivery year. The quantities to be procured will be calculated from the updated March 2017 load forecasts and will be limited to the funds available in the RRB as reported at that time. Should consensus on the March 2017 load forecasts be needed and not be reached, the quantities of RECs to be procured for the 2017-2018 delivery year will be based upon the July 2016 expected load forecast. 2017 Plan at 90.

Further, consistent with prior years, the 2017 Plan once again does not recommend use of the RRB for Ameren or ComEd for renewable energy resource contracts of more than 1 year in length or extending beyond the 2017-2018 delivery year for the 2017 Plan. Even if the IPA believes that curtailments are unlikely for the upcoming delivery years, the 2017 Plan states that past experience shows that customer switching and load migration—and consequent reduction in available RRB funds—can happen suddenly and significantly in Illinois, given the opportunity for load shifting in large chunks due to municipal aggregation. With this risk looming, entering into additional contracts featuring obligations beyond the immediate delivery year using the RRB would be imprudent and unwise, and could result in large and economically inefficient risk premiums in any bids offered by parties understandably concerned about future year curtailments. For Ameren and ComEd, this may limit the use of RRB funds to meeting the technical requirements of the utilities' RPS mandates rather than achieving broader policy goals such as fostering the development of new renewable generation in Illinois. Absent legislative changes to the IPA Act and the PUA, and given the resources currently under contract and continued load volatility, the 2017 Plan opines that this dynamic will likely continue to limit what the IPA can propose for use of the RRB in future years. The IPA states that it will continue to monitor the operation of this dynamic and analyze it in developing future procurement plans. 2017 Plan at 91.

A. Section 8.3 Use of Hourly Alternative Compliance Payments Held by the Utilities

1. Summary

Section 8.3 of the 2017 Plan states that Ameren and ComEd collect ACPs on behalf of customers taking hourly service from the utility. Unlike the ACP funds paid by ARES into the RERF, which are held and administered by the IPA, utility hourly customer ACP funds are held by the utilities. As required by the IPA Act, each utility has disclosed the amount of hourly customer ACP funds held as of May 31, 2016. The 2017 Plan states that for Ameren, the balance is $12,665,469 ($12,348.925 after adjusting for DG REC contracts signed after May 31, 2016); for ComEd, the balance is $27,467,027 ($26,818,750 after adjusting for DG REC contracts signed after May 31, 2016). 2017 Plan at 96.

The 2017 Plan notes that the IPA Act requires that ACP funds from utility hourly customers be used to "increase [the utility's] spending on the purchase of renewable energy resources to be procured by the electric utility for the next plan year by an amount equal to the amounts collected by the utility under the alternative compliance payment rate or rates in the prior year ending May 31." 20 ILCS 3855/1-75(c)(5). Starting with the 2013-2014 delivery year, the Commission approved the use of hourly ACP funds to purchase RECs from any curtailed LTPPAs. In the unlikely event of future curtailments, the 2017 Plan recommends a continuation of that policy, with the caveat that these purchases would be secondary to the already contractually committed use of the hourly ACP funds for the DG procurement. The 2017 Plan also states that the purchase of curtailed RECs from the LTPPAs would take precedence over new DG procurements undertaken in 2017. 2017 Plan at 96-97.

The 2017 Plan states that utilizing the already collected, and otherwise unspent, hourly ACP funds to allow Ameren and ComEd to meet their DG sub-targets appears to be the best way to manage risks associated with longer-term contracts. As the IPA Act requires that contracts for DG resources must be "no less than 5 years" in length, entering into 5-year contracts using existing ACP funds already collected from hourly customers eliminates the load migration risk present with the RRB (from which long-term contracts have been subject to curtailments in the past) while ensuring that there are no impacts on customer rates. The 2017 Plan notes that this approach was proposed by the IPA and approved by the Commission in both the 2015 and 2016 Plans. 2017 Plan at 97.

Although DG systems were eligible to participate in the IPA's prior renewable energy resource procurements, the fall 2015 procurement, specifically targeting DG resources, was the first of its kind conducted by the IPA. The fall 2015 procurement was followed by a subsequent DG REC procurement in June 2016. The 2017 Plan notes that DG procurements held for the utilities in the fall of 2015 and the summer of 2016 featured low participation and fell short of meeting their statutory DG sub-targets. 2017 Plan at 97.

2. Renewables Suppliers' Position

The Renewables Suppliers are comprised of project companies, which hold an LTPPA with one or both of Ameren or ComEd to supply electricity from renewable resources bundled with the associated RECs. Renewables Suppliers Cmnts. ("RS Cmnts.") at 1. The Renewables Suppliers object to the 2017 Plan's proposed use of the utilities' hourly ACP Funds to procure DG RECs. RS Cmnts. at 1.

The Renewables Suppliers note that in its Order on Rehearing in the proceeding considering the 2014 Plan, the Commission ruled that in the event of curtailment of purchases of renewable energy resources under the LTPPAs due to operation of the statutory rate cap (20 ILCS 3855/1-75(c)(2)), funds accumulated by the electric utilities through applying the ACP rate to their customers taking service on the utility's hourly pricing tariff (pursuant to 20 ILCS 3855/1-75(c)(5)), should be used by the utilities to purchase the curtailed LTPPA RECs. *Illinois Power Agency*, Docket No. 13-0546, Order on Rehearing at 53-58 (June 16, 2014) ("*2014 Plan Docket*"). RS Cmnts. at 1-2.

The Renewables Suppliers assert that the 2017 Plan should specify that the spring 2017 DG REC procurement event will not be held until after ComEd and Ameren file their March 2017 load forecast updates and it is determined whether or not curtailments of the LTPPAs for ComEd or Ameren will be necessary. The Renewables Suppliers understand that, as in past years, a utility's March 2017 load forecast update will be adopted as the load forecast to be used for purposes of the 2017-2018 Delivery Year only if it is the consensus of the IPA, Staff, the Procurement Monitor and the applicable utility that the March 2017 update should be used. If there is no such consensus, the utility's July 2016 load forecast will continue to be used. 2017 Plan at 5. The Renewables Suppliers' proposed timing will enable the IPA to proceed with, and size, the spring DG REC procurement knowing whether each electric utility's hourly ACP Funds need to be used to purchase curtailed LTPPA RECs in 2017-2018. RS Cmnts. at 3.

According to the Renewables Suppliers, if the March 2017 load forecast updates indicate a need for LTPPA curtailments in any of the succeeding five years (2018-2019 through 2021-2022), this would inform the IPA's determination of the size of the 2017 DG REC procurements. Although the 2017 Plan observes in a footnote that "because the first of the two DG procurements will almost certainly occur after the March load forecasts are received, those load forecasts will be used to inform a DG procurement budget" (2017 Plan at 3 n.9), the IPA has stopped short of stating that the first 2017 DG REC procurement event will not be held until after the March 2017 load forecasts are submitted and a final determination is made as to whether or not curtailments of the LTPPAs for 2017-2018 are required. The Renewables Suppliers argue that scheduling the first 2017 DG REC procurement after the March 2017 load forecast updates are filed is a common sense precaution. RS Cmnts. at 3-4.

The Renewables Suppliers note that the IPA intends to schedule the DG REC procurement based on the availability of internal and external resources, the timetable for contract development and completion, maximizing bidder participation, and other concerns relating to statutory requirements, but that the IPA provides no explanation of how any of these considerations could necessitate holding the initial DG REC procurement event earlier than late March-early April. Given that the presence or absence of LTPPA curtailments would impact the amount of the accumulated hourly ACP funds that the IPA can budget for the DG REC procurements, it would be prudent for the IPA not to conduct the spring 2017 DG REC procurement until the load forecast updates are filed and it is known whether LTPPA curtailments will be needed for either utility. RS Rep. at 1-2.

The Renewables Suppliers next propose that the 2017 Plan, or the Commission, specify how the amount of the utility's accumulated hourly ACP funds to be allocated to the purchase of curtailed LTPPA RECs should be calculated if it is determined that LTPPA curtailments are needed in 2017-2018. In its Order on Rehearing in the *2014 Plan Docket*, the Commission ruled that curtailed LTPPA RECs should be purchased by the utility, using its accumulated hourly ACP funds, at prices equal to the contract Prices under the LTPPAs less the Day Ahead Hourly Locational Marginal Prices. *2014 Plan Docket*, Order on Rehearing at 57. The Renewables Suppliers explain that while the contract price under each LTPPA is known, the Day Ahead Hourly Locational Marginal Prices are determined throughout the year. Therefore, it is not possible to calculate with certainty what the purchase price will be for curtailed LTPPA RECs in the ensuing period. To take this uncertainty into account, the Renewables Suppliers recommend that the 2017 Plan (or the Commission's order) specify that the amount of the utility's accumulated hourly ACP funds to be allocated to purchasing curtailed LTPPA RECs during 2017-2018 should be 110% of the estimated amount needed to purchase curtailed LTPPA RECs in 2017-2018. RS Cmnts. at 4.

The Renewables Suppliers also note that the IPA states that it does not object to this request for clarification on the methodology for estimating the amount needed to purchase curtailed LTPPA RECs. IPA Resp. at 5. Staff also agrees that the 2017 Plan or the Commission's order should specify how to determine the amount of the utility's accumulated hourly ACP funds to be allocated to the purchase of curtailed LTPPA RECs. Staff requests more information on how the amount needed to purchase curtailed LTPPA RECs would be estimated, and why 110% is the appropriate uncertainty adjustment factor. Staff Resp. at 3-4. As to the first question, the Renewables Suppliers explain that there are three components to the calculation: (i) the number of contracted RECs that will be curtailed in each LTPPA, based on the percentage curtailment, which will be a known number for each LTPPA; (ii) the contract price in each LTPPA, which is known to the IPA and the utility; and (iii) the day-ahead hourly locational marginal prices throughout the year, which are not known at the start of the year. For this third value, an appropriate published forward or futures price index that provides monthly electricity price values for the delivery year in the ComEd or Ameren zone, as applicable to the LTPPA, should be used. With these values, the utility and/or the IPA can calculate the estimated amount needed to purchase curtailed RECs during the 2017 delivery year. RS Rep. at 3.

As to Staff's second question, the Renewables Suppliers do not have a mathematical, statistical, or other technical basis for proposing that the estimated amount be increased by 10% to account for uncertainty in forecasting future day-ahead hourly locational marginal prices during the delivery year. The Renewables Suppliers have simply proposed a 10% factor as a modest adjustment to the estimate to account for this uncertainty. The Renewables Suppliers note that the IPA states that it "believes that 110% constitutes a reasonable amount." IPA Resp. at 5. Adoption of their proposal, the Renewables Suppliers opine, should not depend on whether there is a mathematical or statistical basis for setting the uncertainty adjustment factor at 10%. Further, if a curtailment of a utility's LTPPAs proves to be necessary for the 2017 delivery year, based on the utility's March 2017 load forecast update, and the amount of hourly ACP funds set aside to purchase curtailed LTPPA RECs proves to be higher than actually required, the difference will still be held by the utility and can be used to purchase RECs in a subsequent delivery year. RS Rep. at 3-4.

The Renewables Suppliers have an additional objection relating to the prioritization of accumulated hourly ACP funds to purchase DG RECs over the purchase of curtailed LTPPA RECs. The IPA Plan makes references to hourly ACP funds having been "committed" and "contractually committed" to the purchase of DG RECs procured in the 2015 and 2016 DG REC procurement events. *See, e.g.*, 2017 Plan at 6, 96. Based on the Renewables Suppliers' review of the form contract documents for the ComEd 2016 DG REC procurement, the Renewables Suppliers are unaware that the utility's accumulated hourly ACP funds have been pledged or otherwise committed in the DG REC purchase contracts as the source of payment for the contracted DG RECs. Therefore, the Renewables Suppliers question whether stating that the utility's hourly ACP Funds have been "contractually committed" to pay for the DG RECs procured in the 2015 and 2016 procurement events is an accurate characterization. RS Cmnts. at 4-5.

The Renewables Suppliers state that the Commission established in the Order on Rehearing in the *2014 Plan Docket* that accumulated hourly ACP funds should be used to purchase curtailed LTPPA RECs. This determination was based, in part, on substantial evidence that the curtailment of purchases under the LTPPAs and the consequent loss of contracted revenues by the LTPPA suppliers was damaging the ongoing development of renewable energy facilities in Illinois and outside of Illinois to serve the Illinois market. *See 2014 Plan Docket*, Order on Rehearing, at 3-4, 9-16. The use of accumulated hourly ACP funds to purchase DG RECs under five-year contracts was proposed and implemented for the first time in the 2015 Plan. The Renewables Suppliers see no reason why payment for DG RECs should be a priority use of accumulated hourly ACP funds, taking precedence over purchase of curtailed DG RECs, in any future delivery year. RS Cmnts. at 5-6.

In response to the IPA's argument that there is a statutory obligation for the utilities to purchase DG RECs, the Renewables Suppliers aver that there is also a statutory obligation for the utilities to purchase renewable energy resources (75% of which are to come from wind generation) in accordance with the RPS. 20 ILCS 3855/1-75(c)(1); RS Rep. at 4-5.

The Renewables Suppliers explain that the IPA, specifically to avoid the risks associated with funding REC purchase contracts through the RRB, which had resulted in curtailments of the LTPPAs, chose to fund DG REC purchases from the funding source that the Commission had already ordered be used to purchase LTPPA RECs in the event of a curtailment. In light of this, there is no reason why the use of the utilities' hourly ACP Funds to purchase contracted DG RECs should be given priority over the use of the hourly ACP funds to purchase curtailed LTPPA RECs. RS Rep at 5-6.

If the DG REC contracts entered into in 2015 and 2016 do in fact contractually commit the use of accumulated hourly ACP funds to pay for the contracted DG RECs, the Renewables Suppliers recognize that those contracts cannot be altered. However, for future DG REC procurements, the Renewables Suppliers propose that the contracts should specify that payments on the contracts from hourly ACP funds over the five-year contract period are subject to and subordinate to the use of hourly ACP funds to purchase curtailed LTPPA RECs, should any curtailments of purchases under the LTPPAs be required during the five-year period. RS Cmnts. at 6. This recommendation from the Renewables Suppliers would also apply to 10-year DG REC contracts if the Commission adopts Staff's proposal for a longer contract term. RS Resp. at 2.

Although the ComEd and Ameren load forecasts do not show a need for any LTPPA curtailments in the next five years, the IPA proposes to acquire general (utility-scale) wind and solar RECs for ComEd and Ameren only under one-year contracts, due to the possibility that curtailments could occur in future years. 2017 Plan at 91. If the Commission accepts this perspective, the Renewables Suppliers suggest that to be consistent the Commission should also direct that the five-year DG REC contracts specify that payments on the contracts from hourly ACP funds over the five-year contract period are subject to and subordinate to the use of the hourly ACP funds to purchase curtailed LTPPA RECs, should any curtailments of purchases under the LTPPAs be necessary during that period. RS Cmnts. at 6-7.

Staff asserts that including curtailment provisions in future DG REC contracts would make them less attractive to potential bidders and potentially deter bids or increase bid prices (Staff Resp. at 7), but the Renewables Suppliers note that the Commission directed that hourly ACP funds be used to purchase curtailed LTPPA RECs based on evidence that the LTPPA curtailments and consequent losses of contracted revenues by the suppliers were adversely impacting the development of renewable energy resources in, and for, Illinois. RS Rep. at 6.

Thus, a curtailment provision should be included in the DG REC procurement contracts entered into in 2017 and any future years. At a minimum, as proposed by Ameren, the Renewables Suppliers opine that the IPA should be directed to develop and evaluate several options for consideration to address this issue and to make a recommendation to stakeholders and the Commission. Ameren Resp. at 2; RS Rep. at 6-7.

3. Staff's Position

Staff agrees with the IPA that the Commission should be conservative in proposing and approving new DG procurement commitments. Staff believes that the IPA has been reasonably conservative in this respect by only committing ACP funds that have already been collected, less ACP funds that have already been committed through previous DG procurement events. The IPA has included no projections of new ACP revenue in its previously-approved and its currently-proposed DG REC budgets, even though it is highly likely that there will be substantial new ACP revenues year after year. Staff Resp. at 4.

In principle, Staff does not necessarily oppose the Renewables Suppliers' proposal to compute the amount to be allocated to the purchase of curtailed LTPPA RECs as 110% of the estimated amount needed to purchase curtailed LTPPA RECs in 2017-2018. However, Staff cannot support that proposal unless the Renewable Suppliers, IPA or some other interested party can further explain and justify using a factor of 110% (as opposed to 101%, 105%, or 115%, for example) to account for the cited uncertainty. In addition, it should also be shown how the amount needed will be estimated. Such details should be part of the approved plan if for no other reason than to make the plan clear. Inclusion of such details in the 2017 Plan would have the added virtue of enhancing transparency over the cost of the LTPPAs. Finally, Staff's support for the proposal is conditional on "the amount of the utility's accumulated hourly ACP funds to be allocated" being limited to the sum of hourly ACP revenues already collected minus the sum of hourly ACP funds that have already been committed to other REC purchases through previous procurement events. Staff states that funds that are already committed to other REC purchases should not be clawed back for the benefit of LTPPA suppliers. Staff Resp. at 4-5.

Staff also opposes Renewables Suppliers' proposal to make DG contract payments subordinate to the use of the hourly ACP funds to purchase curtailed LTPPA RECs. The basis for giving the LTPPA suppliers priority over DG REC suppliers is the Renewables Suppliers' argument that the Commission established in the *2014 Plan Docket* Order on Rehearing that accumulated hourly ACP funds should be used to purchase curtailed LTPPA RECs. However, at that time, there were no existing DG contracts to subordinate to the LTPPAs, and the IPA was proposing to use the accumulated ACP funds for the existing LTPPAs during that 2014-2015 plan year, in lieu of entering into any other new contracts (for DG or otherwise). It was not until the following plan (for the 2015-2016 plan year) that the IPA proposed procuring new 5-year DG REC contracts with the ACP funds. As is clear from the Order in the *2015 Plan Docket*, the reduction in funds available for entering into the new DG contracts applied only to the amounts needed to ensure full payment of any prior year (2014-2015) and prompt year (2015-2016) curtailments under the LTPPAs. *See Illinois Power Agency*, Docket No. 14-0588, Order at 6 (Dec. 17, 2014) ("*2015 Plan Docket*"). Neither the 2015 Plan nor the Commission's Order in the *2015 Plan Docket* explicitly states or even suggests including within the new DG contracts provisions for curtailing contract quantities in the event of future LTPPA funding shortages. And, no such curtailment provisions were included in those DG contracts. In contrast, the Commission-approved LTPPAs include provisions explicitly allowing for curtailment under such circumstances, and such provisions may very well have led the Renewables Suppliers to build risk premiums into their bids. Staff Resp. at 6.

Staff supports the status quo with respect to the non-proliferation of curtailment provisions. Such provisions were not inherently or unequivocally beneficial, but were added to the LTPPAs out of necessity, since funding for those 20-year contracts was highly uncertain. However, it is completely unnecessary to add such provisions to the DG contracts, since funding for the DG purchases is assured through the IPA's conservative approach. Furthermore, adding such provisions to DG contracts would make them less attractive to potential bidders and would likely deter bids and/or increase the level of bid prices. Even without such provisions, the IPA has found it very difficult to attract enough bids to achieve the planned DG REC targets (e.g., less than 20% of the 2016-2017 targets have been met through the first two procurement events). To say the least, inclusion of such curtailment provisions would do nothing to attract more bidders to future IPA REC procurement events (for DG RECs or for any kind of RECs). In sum, adding curtailment provisions to DG REC or other REC contracts would be of benefit to no one except the Renewables Suppliers. Staff Resp. at 6-7.

For all the above reasons, Staff opposes the Renewables Suppliers' proposed subordination (relative to the LTPPAs) of current and future DG REC contracts.

4. ComEd’s Position

In calculating the amount of hourly customer ACP funds that are being held by ComEd as of May 31, 2016, ComEd notes that the 2017 Plan made an adjustment for DG REC contracts signed after May 31, 2016 ($648,277), but did not make a similar adjustment for the value of the DG REC contracts signed during 2015 ($984,690). 2017 Plan at 96-97. As a result, Section 8.3 of the 2017 Plan should be revised to reflect an adjusted value of $25,834,060, after taking into account DG REC contracts executed during 2015 and 2016. ComEd Cmnts. at 8.

ComEd responds to the Renewables Suppliers’ objection regarding whether the hourly ACP funds are truly “contractually committed” to pay for DG RECs procured in the 2015 and 2016 procurement events and whether future DG REC procurement contracts should be given a higher priority for using hourly ACP funds than LTPPA RECs. Based on the applicable provisions of the 2016 Plan and the Order in the *2016 Plan Docket*, ComEd believes that hourly ACP funds in an amount equal to the expected future payments under the DG REC contracts have indeed been committed to the 2015 and 2016 hourly ACP contracts and that these funds are not available to purchase LTPPA RECs unless the DG RECs are not delivered as required by their contracts. *2016 Plan Docket*, Order at 60; ComEd Resp. at 8.

ComEd explains that under the current approach, if the IPA determines during the development of a future plan that there will be insufficient hourly ACP funds to purchase both LTPPA RECs and new DG RECs, then the IPA can propose whether or not to forgo a DG procurement and effectively prioritize LTPPA RECs. However, once a DG REC procurement event is completed, sufficient hourly ACP funds should be committed to fully fund the resulting contracts. Alternatively, if the IPA or the Commission concludes that going forward, DG REC contracts do not require hourly ACP funds to be committed to their future payments, then a curtailment provision must be included in the multi-year DG REC contracts to allow for the possibility that the funds that were expected to be available could be redirected for another purpose. ComEd Resp. at 9.

5. Ameren's Position

Upon review of the arguments put forth by the IPA and Staff, Ameren agrees that the Commission should reject the Renewables Suppliers' proposal that future DG REC contracts have curtailment provisions. Ameren Rep. at 2.

6. ELPC's Position

ELPC agrees with the IPA that the Commission should reject the Renewables Suppliers' suggestion that the DG procurement not take place until after the March load forecasts are received and a determination on any necessary curtailment is made. It might be appropriate to consider the needs of LTPPA holders if the hourly ACP fund from which DG contracts are paid were in some way committed to LTPPAs, however as the IPA points out, the use of the hourly ACP fund for LTPPAs is neither a statutory nor contractual obligation. IPA Resp. at 3. Basing procurement timing around concerns unrelated to holding successful procurements that fulfill the statutory requirements of the IPA Act risk limiting the success of procurement events, increasing costs to ratepayers, and setting a bad precedent vis-à-vis other procurement events. In this case, even the LTPPA holders concede that ComEd and Ameren load forecasts show no need for curtailments of long-term contracts over the next five years, so a decision to structure the IPA's larger procurement strategy around that unlikely contingency would not be prudent. ELPC Rep. at 2.

ELPC also agrees with the IPA, Staff, and ComEd that hourly ACP funds are obligated to previously signed DG contracts. ELPC Rep. at 3. ELPC further agrees with the IPA, Staff, and ComEd that the Commission should reject the Renewable Suppliers' proposal to make future DG contracts subordinate to curtailed LTPPAs going forward and endorse a continuance of the current practice of signing DG contracts intended to be paid from hourly ACP funds without introducing curtailment provisions. Both Staff and the IPA make a number of arguments against the prioritization of hourly ACP funds to curtailed LTPPAs over DG resources, including: 1) LTPPA holders were aware of the risk of curtailment (and presumably priced in that risk); 2) past proceedings that approved the use of hourly ACP funds for curtailed LTPPAs were intended to apply to procurement events in the specific years referenced in said proceedings, not future procurement events; 3) in the event it becomes necessary, there are other potential sources of funding for curtailed LTPPAs, but there are no other sources of funding that can be applied to DG contracts; and 4) adding curtailment provisions to DG REC contracts would presumably lessen the attractiveness of contracts to bidders potentially leading to even lower participation and/or higher contracting pricing due to the addition of risk premiums. Based upon the merits of these arguments, ELPC agrees with the IPA that the Commission should approve the use of the hourly ACP funds to meet the IPA's statutory obligations to procure RECs from DG systems without introducing unnecessary complexity and risk into these contracts. ELPC Rep. at 3-4.

7. IPA's Position

The IPA explains that its proposal to procure curtailed RECs using hourly ACP funds was initially proposed in the 2013 Plan and adopted as a convenient mechanism for addressing an unexpected problem resulting from massive load migration due to municipal aggregation and its resulting impact on the state renewable energy portfolio standard's rate impact cap and as a more palatable alternative than modifying existing contracts. Hourly ACP funds had been collected but were not earmarked for any other use, and their utilization for this purpose represented a convenient solution to an unfortunate challenge. But the use of hourly ACP funds to purchase curtailed RECs is not a statutory obligation, it is not a contractual obligation, and its approval in the *2014 Plan Docket* was based only upon the record in that proceeding (in which no other use of hourly ACP funds was being considered) and was not necessarily intended to be binding upon each subsequent procurement plan or any future use of hourly ACP funds. The IPA further notes that curtailments that triggered the use of ComEd's hourly ACP funds to purchase LTPPTA RECs occurred in the 2013-2014 and the 2014-2015 delivery years, but have not occurred since then, and Ameren has not experienced a curtailment. IPA Resp. at 3.

Alternatively, the IPA states it has a statutory obligation to procure RECs from DG systems. *See* 20 ILCS 3855/1-75(c)(1); *2016 Plan Docket*, Order at 123. Under the IPA Act, the "procurement of renewable energy resources from distributed renewable energy generation devices shall be done on an annual basis through multi-year contracts of no less than 5 years." 20 ILCS 3855/1-75(c)(1). But as the Commission has repeatedly held, any use of the RRB for new contracts beyond one year in length would be inappropriate given the ongoing curtailment risk for the existing LTPPAs that could result from an over-commitment in future years of the RRB due to changes in the eligible retail customer load. *See, e.g.*, *2015 Plan Docket*, Order at 286; IPA Resp. at 3-4.

Faced with a statutory obligation to procure RECs from DG systems through 5-year (or longer) contracts but without reliable availability of the RRB, the IPA opines it is left with no choice but to utilize already-collected, utility-held hourly ACP funds for that longer-term procurement. This choice is limited to ComEd and Ameren. MidAmerican does not have any LTPPAs and has very limited customer switching, so for MidAmerican, use of the RRB for DG contracts does not pose the same risk. Already-collected hourly ACP funds feature no risk of diminishment through load migration (and carry no appropriation or diversion risk as they are held by the utility, and not the state), making certain their availability for future years of a five-year contract. And while in the unlikely event of a curtailment, the Renewable Suppliers could receive full (or very nearly full) value for curtailed RECs through the IPA's procurement of those curtailed RECs using the RERF (as done by the IPA in 2013) or through the sale of those RECs in other markets or to other parties, the IPA notes that only utility funds could be utilized to meet Section 1-75(c)'s DG RECs statutory targets. Based on this reasoning, the IPA's proposed approach for using hourly ACP funds for a DG procurement was likewise proposed (and ultimately approved) in the IPA's 2015 and 2016 Plans. The IPA opines that the 2017 Plan features a balanced, thoughtful approach to competing concerns that prioritizes making LTPPA holders whole, but not at the expense of meeting statutory requirements. IPA Resp. at 4.

Turning to the specific proposals of the Renewable Suppliers, the Renewable Suppliers first argue that the IPA must specify that its first DG procurement should take place after the March load forecasts are received and a determination on the necessity of curtailment is made. The IPA states that procurements are scheduled and conducted based upon the availability of internal and external resources, the timetable for contract development and completion, maximizing bidder participation, and other concerns related to meeting statutory requirements at the lowest total cost over time. The IPA avers that procurements have never been, and should never be, scheduled based upon the narrow financial interests of non-participants. While the IPA believes it is unlikely that its first DG procurement will be conducted before March 15, it must retain the right to schedule its procurements based upon criteria related to the success of the procurement itself—and not based on the needs of three entities already holding LTPPAs. IPA Resp. at 5.

Second, the Renewable Suppliers request specificity around how the amount of hourly ACP funds allocated to the purchase of curtailed LTPPA RECs should be determined, as the actual price of those RECs would not be known. The IPA does not object to this request for clarification, and believes that 110% constitutes a reasonable amount. IPA Resp. at 5. The IPA further agrees with Staff that, if to be adopted, this proposal would benefit from supporting analysis, and, at a minimum, a clearly stated methodology and rationale. IPA Rep.at 5.

Third, the Renewable Suppliers request that future DG procurement contracts include a clause stating that such contracts are "subject to and subordinate to the use of Hourly ACP Funds to purchase curtailed RECs, should any curtailments of purchases under the LTPPAs be required during the five-year period." RS Cmnts. at 6. The IPA strongly objects to this request. Using hourly ACP funds for DG procurements constitutes the only available pathway to meet an immutable statutory requirement; using hourly ACP funds to purchase curtailed RECs constitutes one (of many) pragmatic solutions to addressing an unfortunate and unexpected problem for certain existing contract holders. Further, adoption of this request would require new curtailment provisions to be included in DG contracts (as funding for such contracts would now be subject to the status of LTPPA curtailments). This undermines the very purpose of using hourly ACP funds for five-year DG contracts: the certainty of available funds so as to avoid creating any new curtailment risks. As this proposal would inappropriately prioritize the limited financial interests of LTPPA holders over the IPA's availability to use collected funds for the intended purpose of meeting statutory targets, the IPA argues that it must be rejected. IPA Resp. at 5-6.

As detailed in its Plan, the IPA has not yet made its DG procurements achieve their desired outcomes, with past DG procurements featuring limited participation and results falling well short of statutory goals. To fix this process (and informed by the analysis of the Commission's Procurement Monitor and parties commenting on the Draft Plan), the 2017 Plan features thoughtful and balanced modifications to the DG procurement process to maximize participation and ensure that statutory goals are met at the lowest possible cost. IPA Rep. at 3. According to the IPA, making new DG contracts subordinate to existing LTPPAs in allocating hourly ACP funds would require the introduction of new curtailment provisions into DG contracts, essentially telling potential DG contract holders that the utilities cannot promise to actually purchase the RECs under contract because they cannot promise the availability of funds. This risks submarining all parties' extensive efforts at turning an ineffective process into a productive one. As generating participation from bidders for prior DG procurements without such provisions proved challenging, it is impossible to envision new bidders flocking to a process featuring such unfavorable new terms. IPA Rep. at 3.

In Comments, ComEd notes that the reporting of ComEd's hourly ACP fund balance in the 2017 Plan did not properly adjust for the value of the DG contracts entered into in 2015 and requests a correction. The IPA acknowledges this oversight and agrees that this value should be corrected. IPA Resp. at 8-9.

8. Commission Analysis and Conclusion

The IPA proposes that the hourly ACP funds be allocated in the following order: 1) contracts already awarded through prior DG REC procurements, 2) curtailed RECs stemming from the 2010 LTPPAs, and 3) new DG REC contracts. The Commission agrees with this prioritization of the use of hourly ACP funds. The record shows that the DG REC contracts already in place do not have terms that allow for curtailment, but the LTPPAs do. Thus, the Commission finds that using the accumulated hourly ACP funds to pay for the existing DG REC contracts is appropriate.

Also, because of the statutory requirement that DG REC contracts must have a five year term, a secure source of funding is necessary. The Commission notes that the 2017 Plan only discusses accumulated hourly ACP funds, but Staff points out that it is highly likely that there will be substantial new ACP revenues year after year because of no load migration. Staff Resp. at 4. Thus, the Commission finds it reasonable to use the hourly ACP funds as a secure source for these long term contracts.

The Commission also notes that all parties seem to agree that curtailments are unlikely for 2017-2018, which would render the Renewables Suppliers' proposal unnecessary. Moreover, the IPA states that in the event a curtailment is necessary, the IPA could use the RERF to purchase the LTPPA RECs, which further lessens the need for the Renewables Suppliers' proposal. Therefore the Renewables Supplier's proposal to give the LTPPAs priority over existing DG REC contracts is denied.

For these same reasons and also because the LTPPAs are primarily funded from the RRB, the Renewables Suppliers' proposal to impose curtailment provisions on future DG RECs is also denied. The Commission directs that once a DG REC procurement is completed, sufficient hourly ACP funds should be committed to fully fund the resulting contracts.

The Renewables Suppliers also suggest that the spring 2017 DG REC procurement should not be held until the utilities' March 2017 load forecasts are submitted and a final determination is made as to whether curtailment of the LTPPAs for ComEd or Ameren is required for 2017-2018. The Commission declines to adopt this proposal. The Commission finds persuasive the IPA's statement that procurements are scheduled and conducted based upon the availability of internal and external resources, the timetable for contract development and completion, maximizing bidder participation, and other concerns related to meeting statutory requirements at the lowest total cost over time. This is a reasonable approach and will not be modified by the Commission.

Although the record shows that a curtailment of the LTPPAs is unlikely for the 2017-2018 period, the Commission agrees that the 2017 Plan should specify how to calculate the appropriate amount to be set aside for the purchase of curtailed LTPPA RECs, if necessary. The Renewables Suppliers' methodology for calculating the amount to be set aside, with a 10% increase to account for uncertainty, is the only proposal presented. The Commission notes that no party objects to the Renewables Suppliers' proposal (although Staff does not support it either). The Commission finds it to be a reasonable solution, and it is adopted.

The Commission agrees with ComEd and the IPA that ComEd's hourly ACP fund balance should be corrected to adjust for the value of DG contracts entered into in 2015.

B. Section 8.4 Distributed Generation Procurement and Section 8.4.1 Procurement Process

1. Summary

Section 8.4 of the 2017 Plan states that given the limited amount of distributed generation currently in Illinois, the success of DG procurement hinges on the ability of the Illinois DG market both to self-organize and to continue to grow. To encourage increased participation, the 2017 Plan will allow bids to contain DG systems of all qualifying sizes and resource types. Consistent with the law defining a distributed generation device, systems must be no larger than 2,000 kilowatts ("kW"). The confidential benchmarks used by the Procurement Administrator to evaluate bids may depend on system size, technology, and other factors. Consistent with the approach taken in the supplemental photovoltaic ("SPV") procurement (which also featured the requirement that 50% of RECs come from systems of below 25 kW in size) and with past DG procurements, bids that meet or exceed the benchmarks will be selected on the basis of price, and on the basis of trying to achieve a 50-50 balance of RECs procured from each of the two categories of systems, namely systems below 25 kW and systems of 25-2,000 kW in size. 2017 Plan at 97.

Also, the 2017 Plan states that contracts will provide for each system under the contract to have five full years of REC deliveries beginning with each system's first delivery of RECs, and allowing for development time between the procurement event and the first REC delivery to facilitate the construction of new systems. 2017 Plan at 97.

The IPA explains in the 2017 Plan that it has held two DG procurements to date and neither procurement came close to achieving its target REC procurement volumes, and each had only one winning bidder. In both procurements, additional entities beyond the winning bidder took part to varying degrees in every step of the bidding process, but challenges (including for example, assembling bids that would meet the requirements of the procurement and obtaining necessary letters of credit by the bid date) limited ultimate participation. 2017 Plan at 97.

According to the 2017 Plan, available funding has not been a constraint on the DG procurement process, and therefore, the IPA's DG REC procurements will continue to use hourly ACP funds for Ameren and ComEd and use the RRB for MidAmerican (including forecasts of the available budget over the life of the contracts). The IPA states that it will procure DG RECs until funds are fully allocated or the utilities' DG goals are met, whichever comes first. The products to be procured are RECs from DG systems that are interconnected with Ameren, ComEd, MidAmerican (Illinois service territory only), Mount Carmel, a municipal utility in Illinois, or a rural electric cooperative in Illinois as required by Illinois law. The 2017 Plan states that DG systems need not be in the service territory of the utility purchasing the RECs. 2017 Plan at 98.

In Section 8.4.1 of the 2017 Plan, the IPA explains that its approach to procuring DG RECs will consist of two procurement events in a competitive bid process consistent with the requirements of Section 16-111.5 of the PUA and Section 1-75(c) of the IPA Act and as were conducted in the 2015 and 2016 procurements. Timing of the procurement events will be determined at a later date based upon whether the IPA determines that it will be conducting an April 2017 contingency procurement under the SPV Plan and other factors. 2017 Plan at 98.

2. Staff's Position

Staff states, that while it is conceivable that adding a second DG procurement in 2017 could increase the number of bids and aid the IPA in achieving the target number of RECs, it seems just as likely to spread already lackluster interest among potential suppliers even thinner. Also, Staff notes that the already substantial administrative costs associated with DG procurement will increase. While Staff is not opposed to the IPA's experiment of doubling the number of DG procurement events, Staff recommends that the IPA instead, or also, consider doubling the length of the contractual delivery period from five to ten years. Review of the ACP funds currently available (i.e., ignoring future ACP revenues collected) suggests that those funds alone spread out over ten years would be sufficient to purchase at least four times the number of DG RECs purchased through the last two DG procurements combined. Furthermore, Staff opines that to the extent to which doubling the contract term to 10 years would improve the attractiveness of the contracts to potential suppliers, it seems likely that the average winning prices resulting from the procurement would be lower and the quantity purchased closer to the targets. Staff Cmnts. at 4-5.

Staff notes that the IPA, ELPC, ISEA, and the Renewables Suppliers object to its proposal to split the annual quantity targets and spending limits for DG RECs evenly between 5 and 10 year contracts acquired through one or two procurement events; they prefer the IPA's proposal to utilize solely 5-year contracts acquired through two procurement events. Furthermore, Staff notes that no potential bidders support its proposal. Hence, in order to limit the issues in the current proceeding, and without waiving its right to bring up the issue in future proceedings, Staff is withdrawing its proposal from the current proceeding. Staff urges the IPA and the Commission to remain receptive of such alternatives in the future, if participation and the volume of bidding in DG REC procurement events continue to underwhelm. Staff Rep. at 3.

Staff also questions the following paragraph, which states:

> Timing of the procurement events will be determined at a later date based upon if the IPA determines that it will be conducting an April, 2017 contingency procurement under the Supplemental Photovoltaic Plan, and other factors.

2017 Plan at 98. Staff asserts that it is unclear why the IPA is referring to a future "contingency procurement under the Supplemental Photovoltaic Plan." The SPV Plan was filed in 2014, pursuant to Section 1-56(i) of the IPA Act. After completing three procurements specified in that plan, all funds that were earmarked by Section 1-56(i) for the SPV Plan procurements ($30 million) have been contractually committed, rendering moot the need for a fourth contingency procurement event. If the IPA is contemplating that such a contingency procurement may be necessary due to contract defaults or to under-performance by its REC suppliers, to a change in the law whereby additional funds are earmarked for the SPV Plan, or some other reason why such a contingency procurement could become possible, then the 2017 Plan should be amended to make those circumstances clear. Otherwise, Staff asserts that the reference to a future "contingency procurement under the Supplemental Photovoltaic Plan" should simply be removed from the Plan. Staff Cmnts. at 6.

3. Renewables Suppliers' Position

The Renewables Suppliers urge the IPA and the Commission to limit the DG REC contracts to the minimum, statutorily-required 5-year term, as proposed in the IPA Plan. The Renewables Suppliers recognize that the 2017 DG REC contracts are to be funded entirely from a fixed amount of hourly ACP funds that will already have been collected by each utility and will be known at the time of the procurement event(s). However, a longer contract term than 5 years – which would extend beyond the 5-year forecast period – simply increases the risk of future events that could result in the need to use the hourly ACP funds for other purposes. Further, the IPA's proposed 5-year contract term for the 2017 DG REC procurements is already much longer than the one-year contract lengths that the IPA is proposing for other REC procurements. RS Resp. at 2.

4. ELPC's Position

While some of the issues raised by Staff are reasonable, ELPC believes the IPA is better placed than Staff to balance the pros and cons of various procurement approaches and design a successful procurement of renewable resources. ELPC agrees with Staff that holding more than one procurement event will increase administrative costs, but ELPC expects that holding more than one procurement event will lower barriers to entry for DG REC suppliers that are small businesses and better harmonize DG procurements with the market cycle for smaller solar DG projects. ELPC Resp. at 2-3.

In response to Staff's suggestion to evenly split the spending limits between 5-year and 10-year contracts, ELPC agrees with Staff that longer terms can increase contract attractiveness to suppliers, all else being equal; however all else may not be equal in this case. Ten-year contracts spread payments out over a longer period, which may prove unattractive to suppliers that prefer to receive payments sooner. More importantly, ELPC believes that splitting the DG procurement between 5- and 10-year contracts will add unnecessary complexity to the procurement event that would dilute supplier interest and, potentially, increase transaction costs (both administrative and suppliers' time investment) at the margin. For this reason, ELPC recommends against splitting the DG procurement evenly between 5- and 10-year contracts. ELPC Resp. at 4.

5. ISEA's Position

ISEA supports the IPA inclusion of 2 procurement events in 2017 Plan. ISEA opines that a single event will chill the market as projects identified after that procurement event would wait until 2018 before proceeding. ISEA states that this would encourage greater participation in the DG REC Procurement and open the solar market in several ways. First, solar in Illinois is a nascent market. Hosting more than one procurement per year would enable multiple entry points into solar for both potential system owners as well as prospective solar developers. Additionally, hosting only a single event will have an adverse impact on the financial resources for solar installation businesses and developers intending to purchase speculative RECs. Finally, limiting the DG REC procurement to a single event will have an unintended consequence of creating a market barrier for those interested in entering the market mid-year. ISEA Resp. at 1-2.

ISEA supports the IPA's intention to host two procurement events in the 2017 Plan in order to create a robust and growing industry. Feedback from participants in the SPV Procurement and its success in promoting solar penetration in Illinois supports the need for multiple procurements within a single energy procurement year. ISEA Resp. at 2.

According to ISEA, doubling the length of the delivery period may hamper adoption of solar. A key directive for the IPA is to procure RECs in a cost-effective manner. As such, ISEA polled several of its industry members and no benefit has been identified in association with moving to a 10-year REC. ISEA is concerned this change would simply stretch out the payment period and negatively impact a solar owner's financial return. Furthermore, this change would influence the auction and confidential benchmarks in ways that will be difficult for bidders to anticipate, causing increased confusion and trepidation in bidding. As the IPA has now offered five REC procurements featuring a 5-year REC contract, the ISEA recommends consistency for 2017. ISEA Resp. at 3.

6. IPA's Position

While the IPA appreciates Staff's desire to minimize costs through a longer contract (and agrees that the Supplier Fee in prior DG procurements has been higher than ideal), the IPA states that comments received on the Draft Plan—including those from entities that might participate in the DG procurement itself—demonstrated a strong desire for multiple procurements. Reducing the Supplier Fee would be aided by increased participation by bidders, a challenge that many of the IPA's DG procurement reforms are meant to address. Although the IPA does not oppose a longer contract term, it cautions that a longer contract term may not necessarily spur additional participation. Moreover, through locking in purchase requirements of RECs from DG systems over a longer period of time, Staff's proposal could have the unintended consequence of stifling efforts to develop new DG systems in future years, as longer obligations would continue to constrain the available budget well into the future. IPA Resp. at 6-7.

The IPA states that bid evaluation under a mix of contract lengths would offer new challenges that have not been encountered in prior IPA procurements, likely adding additional costs, complexity, and uncertainty to both bidders' bidding behavior and to bid evaluation and selection. Multiple contract lengths also carry the additional downside of an increase in administrative burden faced by the utilities serving as the counterparty to DG contracts, forcing utilities to both assume contract administration responsibilities resulting from the same procurement for a longer period (10 years, as opposed to only 5), and administering a second set of contract types. Notably, to the extent that bidders' perspectives were represented in comments on the Draft Plan or have been expressed in filings in this proceeding, all have been strongly supportive of multiple procurement events. *See* ISEA Resp. at 1-2. As this feedback demonstrates that, on balance, the benefits of multiple procurement events outweigh additional costs to the very entities forced to bear those costs, the IPA continues to believe that holding two DG procurement events constitutes a sound approach to maximizing DG procurement participation. IPA Rep. at 5-6.

Staff also states that references to a contingency procurement under the SPV Plan are "confusing" and should be clarified or removed. The IPA does not view these references as "confusing," as the contingency SPV procurement referenced in the 2017 Plan is expressly contemplated in the SPV Procurement Plan approved by the Commission in Docket No. 14-0651. *Illinois Power Agency*, Docket No. 14-0651, Order (Jan. 21, 2015). While the IPA's three supplemental procurements did commit the full $30 million budget, some projects have not been successfully developed by their required deadlines, and other projects are still yet to be identified or developed with deadlines still to come. It is not yet clear whether the balance of available funds freed through undeveloped projects will be sufficient to justify holding a contingency procurement event, and the IPA will determine whether to conduct a contingency supplemental procurement in early 2017. IPA Resp. at 7-8.

To address Staff's concern, the IPA would support adding additional information and context about the contingency procurement as a footnote in the Plan. The IPA also notes that the Plan as drafted erroneously refers to the contingency procurement as potentially occurring in April 2017 while the SPV Plan describes it as taking place in "early 2017," and thus seeks Commission authorization for a correction to "early 2017" for its Final 2017 Plan. IPA Resp. at 8.

7. Commission Analysis and Conclusion

The Commission notes that, based on the comments of other parties, Staff has withdrawn its proposals. Therefore, at this time, the Commission accepts the IPA's proposal to hold two DG REC procurements for five-year contracts.

Staff also raised a question regarding language in the 2017 Plan referencing an SPV Plan contingency procurement. The IPA explained its inclusion and further offered to include a footnote with additional information. The Commission agrees with Staff that more information would be helpful, and the IPA is directed to include the proposed footnote. The IPA is directed as well to change the date of the contingency procurement from "April 2017" to "early 2017."

C. Section 8.4.3 Credit Requirements and Bidder/Supplier Fees

1. Summary

In Section 8.4.3 of the 2017 Plan, the IPA provides a list of its proposals for fees and credit requirements associated with the DG REC procurement. The IPA states that to encourage increased participation, to lower the barriers for smaller local installers, to reduce administrative burdens on the utility, and in recognition that the greatest risk of non-delivery resides in the inability to successfully develop a DG system (rather than in the system's ability to delivery RECs once energized and interconnected), there will not be credit requirements, including credit requirements with the utilities, other than those listed. Should the IPA draw on the letters of credit for non-performance, the IPA will use those funds collected to lower the supplier fees for future DG procurements. Failure of a system to begin REC deliveries will impact the given utility's achievement of its DG goals under Section 1-75(c) of the IPA Act, and the IPA will adjust future DG procurement targets to reflect those changes. 2017 Plan at 101.

2. Ameren's Position

Ameren takes no position on the IPA's proposal regarding the removal of DG REC credit provisions for the utilities, but provides the following observations. First, in the event of contractual default, the replacement DG RECs, if required, may be at a different price relative to the price associated with the defaulted DG RECs. In the event replacement DG RECs are at a higher price, the funds already collected and held by the utility may eliminate or reduce any incremental cost to customers. The same is not true of energy and capacity contracts where costs for contracts are not collected in advance of delivery. While Ameren recognizes that the IPA is not making a recommendation to change credit provisions under energy and capacity contracts, Ameren notes that the DG REC credit proposal is unique to a situation where funds have already been collected from customers. The same is not true for energy and capacity contracts where elimination of credit provisions in those contracts would result in incrementally higher customer costs under a scenario where default occurs and replacement prices are higher relative to the defaulted price. Ameren Cmnts. at 2-3.

3. IPA's Position

In response to Ameren and given the nature of DG RECs, the IPA opines that any new shortfalls could easily be accounted for in future procurements, and observes that while the price of "replacement" RECs could be higher, those RECs could be lower in cost as well—especially given the continuing reduction in costs associated with new DG systems. Ameren's second observation relates to the difference between the credit requirements proposed for the DG procurement and those required for energy and capacity procurements. The IPA agrees that these proposed credit requirements are fundamentally different and explains its proposed DG credit requirements are uniquely tailored to risks posed by a default on a DG REC contract and should not be used to suggest that the credit requirements for energy and capacity should be changed. A failure to deliver energy or capacity is a fundamentally different (and larger) risk proposition than a failure to deliver DG RECs, and the IPA's DG procurement proposal reflects that difference. IPA Resp. at 8.

4. Commission Analysis and Conclusion

The Commission appreciates the comments of the parties. There is no issue to be resolved, and no modification to the 2017 Plan is necessary.

V. SECTION 9 ENERGY EFFICIENCY

Chapter 9 of the 2017 Plan sets out recommendations for the consideration and approval of incremental energy efficiency programs under Section 16-111.5B of the PUA. The 2017 Plan notes that this Section requires the IPA to include an assessment of opportunities to expand the programs promoting energy efficiency measures that have been offered under plans approved pursuant to Section 8-103 of the PUA or to implement additional cost-effective energy efficiency programs or measures. 220 ILCS 5/16-111.5B(a)(2); 2017 Plan at 103.

The 2017 Plan states that the IPA bases its recommendations on "an assessment of cost-effective energy efficiency programs or measures that could be included in the procurement plan" submitted to it by the utilities as part of their July 15th load forecasts. 220 ILCS 5/16-111.5B(a)(3). This annual assessment provided by the utilities is required to include: 1) the "[i]dentification of cost-effective energy efficiency programs or measures that are incremental to those included in energy efficiency and demand-response plans approved by the Commission pursuant to Section 8-103 of this Act" (220 ILCS 5/16-111.5B(a)(3)(C)); 2) an "[a]nalysis showing that the new or expanded cost-effective energy efficiency programs or measures would lead to a reduction in the overall cost of electric service" (220 ILCS 5/16-111.5B(a)(3)(D)); and 3) an "[a]nalysis of how the cost of procuring additional cost-effective energy efficiency measures compares over the life of the measures to the prevailing cost of comparable supply" (220 ILCS 5/16-111.5B(a)(3)(E)). 2017 Plan at 103.

The 2017 Plan explains that Section 16-111.5B was originally enacted as part of Public Act 97-0616, the Energy Infrastructure and Modernization Act, in 2011. Its provisions are meant to complement, enhance, and expand the utilities' existing energy efficiency program portfolios required by Section 8-103 of the PUA through the inclusion in the IPA's annual procurement plans of "new or expanded . . . incremental" programs that would otherwise not be included in the Section 8-103 portfolios due to the operation of the 2.015% rate impact cap in Section 8-103. *See* 220 ILCS 5/8-103(d). To identify these incremental programs, the utilities are required to "conduct an annual solicitation process for purposes of requesting proposals from third-party vendors" developed "consistent with the manner in which it develops requests for proposals under plans approved pursuant to Section 8-103 of this Act, which considers input from the Agency and interested stakeholders." 220 ILCS 5/16-111.5B(a)(3). The results of the RFP process are provided to the IPA as part of each utility's assessment. Under this structure, the IPA then "shall include" in its annual plan "energy efficiency programs and measures it determines are cost-effective" (220 ILCS 5/16-111.5B(a)(4)) and the Commission "shall approve" those programs and measures "if the Commission determines they fully capture the potential for all achievable cost-effective savings, to the extent practicable, and otherwise satisfy the requirements of Section 8-103" of the PUA (220 ILCS 5/16-111.5B(a)(5)). 2017 Plan at 103.

Section 9 of the 2017 Plan includes discussion related to programs and measures which the IPA recommends for inclusion in the 2017 Plan as well as discussion of other issues related to the operation of Section 16-111.5B, including the status of issues designated for workshop discussion through prior Commission Orders. 2017 Plan at 103.

A. Section 9.2 2016 Section 16-111.5B SAG Workshop Subcommittee

1. Summary

The 2017 Plan notes that in approving the 2016 Plan, the Commission directed parties to consider multiple issues through Stakeholder Advisory Group ("SAG") workshops. Five discrete issues identified by the Commission in the Order in the *2016 Plan Docket* were taken under consideration by the SAG workshop process. The IPA believes that significant and meaningful progress was made in the consideration of all five issues. While the fourth and fifth issues resulted in some unresolved differences between parties, the 2017 Plan states that none were so significant that the IPA believes further clarification from the Commission is absolutely essential for approval of the 2017 Plan and proposed energy efficiency programs. The fourth issue, addressed here, was: administrative cost tracking, categorizing, reporting and analysis (total resource cost ("TRC") test analysis for Section 16-111.5B programs). 2017 Plan at 106.

2. Staff's Position

Staff asserts that the Commission should require transparent reporting of all expected Section 16-111.5B energy efficiency costs by directing the utilities to report and the IPA to include in the 2017 Plan, the total expected costs to be incurred for Section 16-111.5B. Staff Cmnts. at 7.

Staff points out the Commission's directive from the last IPA procurement plan docket. Specifically, the *2016 Plan Docket* states:

> It seems that even after the Commission ordered the utilities to track their administrative costs in Docket No. 14-0588, the utilities are not clear as to what administrative costs should be tracked, and, as ComEd has noted, *it is unclear what Staff proposes with respect to additional reporting and whether it is needed. These topics should be thoroughly addressed and determined with specificity in workshops conducted by the SAG.*

2016 Plan Docket, Order at 95 (emphasis added). The Commission explicitly ordered that the additional reporting of costs should be thoroughly addressed and determined with specificity in the workshops. Given consensus was not able to be reached among the parties participating in the workshops, Staff maintains that it is appropriate for the Commission to resolve this disputed issue in this proceeding in order to help ensure full transparency in the reporting of expected Section 16-111.5B costs in future procurement plans. Staff proposes that the Commission require Ameren and ComEd to report all expected Section 16-111.5B costs to the IPA in their Section 16-111.5B energy efficiency assessment submittals. Furthermore, the Commission should require the IPA, based upon this information, to report total expected Section 16-111.5B energy efficiency procurement costs in its procurement plan filings.

In contrast to Staff's position, Staff notes that some parties have taken the position that other Section 16-111.5B costs beyond those impacting the TRC test analysis of individual programs are already reported to the Commission in reconciliation filings, and submittal to the IPA of this additional information is neither necessary nor required by the governing law. 2017 Plan, App. H (Report from the Illinois Energy Efficiency Stakeholder Advisory Group (IL EE SAG) 2016 Section 16-111.5 B Workshop Subcommittee) ("2016 SAG Report"), 25. Staff disagrees. Staff Cmnts. at 8.

As an initial matter, when making program-by-program decisions, Staff supports an incremental evaluation of cost-effectiveness. That is, whether an additional program is approved should depend upon the expected program-specific incremental benefits exceeding its expected program-specific incremental costs. In making individual program decisions, such an approach does not and should not directly consider non-scalable non-program-specific Section 16-111.5B costs. Staff opines that if the incremental benefits from the program exceed any additional incremental costs from the program, then the program will increase net benefits produced by Section 16-111.5B programs in total. Staff Cmnts. at 8.

On the other hand, the IPA or the Commission cannot determine the impact of the Section 16-111.5B portfolio on consumer bills without consideration of non-scalable non-program-specific Section 16-111.5B costs. *See* 2016 SAG Report. Staff explains that non-scalable, non-program-specific Section 16-111.5B costs are costs incurred due to Section 16-111.5B that are not program specific and that are largely fixed and generally not dependent upon budgets of approved Section 16-111.5B programs. A plan which is both transparent and capable of being audited must include reporting of the full expected cost of implementing Section 16-111.5B. Staff Cmnts. at 8-9.

As a practical matter, it is not entirely clear whether utilities have reported all Section 16-111.5B costs. Ameren indicates that it excluded fixed or non-scalable costs when performing cost benefit tests, but does provide a percentage estimate of 1.55% for non-scalable costs. 2017 Plan, App. B at 115 n.247. It is not evident, to Staff, from either the 2017 Plan or the attached appendices the extent to which ComEd did or did not include any non-scalable non-program-specific Section 16-111.5B costs in its submission to the IPA. Staff Cmnts. at 9.

Whether or not the utilities include realized non-scalable non-program-specific Section 16-111.5B costs at some later date, in reconciliation dockets, annual reports, or elsewhere, has no bearing on whether the costs should be reported as part of the procurement planning and approval process. Making these estimates available during the procurement planning and approval process, rather than later, provides the IPA, the Commission, and the public with an estimate of total projected utility Section 16-111.5B energy efficiency spending – information that should be available in order to make statutorily-required energy efficiency procurement plans transparent and auditable. Based upon the above, the Commission should require transparent reporting of all expected Section 16-111.5B energy efficiency costs by directing the utilities to report, and the IPA to include in its Plan, the total expected costs to be incurred for Section 16-111.5B. Staff Cmnts. at 9.

Parties imply that non-scalable non-program-specific cost disclosures are not consistent with the statutory requirements for Section 16-111.5B or that there is no legal basis for requiring such information. IPA Resp. at 10; ComEd Resp. at 8. Staff disagrees. Section 16-111.5B(a)(3) requires, among other things, an assessment of whether programs reduce the overall cost of electric service and how the cost of such measures compares to the prevailing cost of supply. Again, when assessing the incremental value of adding a program to the collection of Section 16-111.5B programs, this assessment should be done ignoring non-scalable non-program-specific costs. It does not mean, however, that the IPA and the Commission should not consider whether Section 16-111.5B programs will in total prove costlier than the cost of comparable supply or raise the overall cost of electric service for the utilities' customers. Staff Rep. at 5.

Both the IPA and ComEd object to Staff's request to make the Section 16-111.5B plan capable of being audited. Staff explains that its use of this terminology implies nothing more than that the IPA Plan should include information so that the IPA, Commission, and any other interested party can examine the plan to determine how the costs of Section 16-111.5B programs compare to the cost of comparable supply, how much they raise or lower the overall cost of electric service for the utilities' customers, and the impact of these programs on customer bills. Staff Rep. at 5-6.

The IPA argues that reporting non-scalable non-program-specific costs will create confusion regarding program benefits. This is precisely the opposite of the impact of Staff's proposal. Failing to incorporate all costs associated with Section 16-111.5B provides a misleading picture of the expected costs associated with Section 16-111.5B as well as the net benefits of Section 16-111.5B. By failing to report a portion of Section 16-111.5B costs, the actual net benefit of the Section 16-111.5B programs in total is certainly less than an assessment of net benefits that includes only a partial reporting of costs.

The IPA argues that utilities' estimates of costs are best guesses and may prove inaccurate. Staff opines that this is true of all program costs and benefits in procurement plans. Indeed, the 2017 Plan is built around estimates, and the utilities' estimates of their own Section 16-111.5B costs are just as informative as any other estimates that form the basis for the IPA Plan. Staff Rep. at 6.

Finally, the IPA states that Staff fails to assert that non-scalable non-program-specific costs are not available to Staff currently or available elsewhere. To be clear, ComEd's best estimate of the expected full non-scalable non-program-specific costs associated with the 2017 Plan have not been provided to Staff and are not, to Staff's knowledge, publicly available. They will not be filed in proceedings or filings prior to when the Commission acts to approve the IPA Plan. Thus, even if they were reported on an ex post basis, they would not provide information to the IPA or the Commission on the expected value of the 2017 Plan. Therefore, absent approval of Staff's proposal, the IPA, the Commission, and the public will not know the full expected cost of Section 16-111.5B before programs are implemented. Staff Rep. at 6-7.

For all of these reasons, the Commission should require Ameren and ComEd to report all expected Section 16-111.5B costs to the IPA and for the IPA, based upon this information, to report total expected Section 16-111.5B costs in its procurement plan filings. Staff Rep. at 7.

3. ComEd's Position

As evidenced by the consensus items approved in recent procurement plan orders (*See 2016 Plan Docket*, Order at 82-83; *2015 Plan Docket*, Order at 226-227), utilities and stakeholders have devoted substantial time and resources to exploring and reaching consensus regarding administrative cost tracking issues raised by Staff. The present proposal, however, is disconnected from any statutory requirement and would serve no ostensible purpose – indeed, the information sought by Staff does not support any determination required to be made in this docket under Section 16-111.5B. The statute does not require the submission of non-program administrative costs, and, as Staff admits, the cost-effectiveness analysis does not require this information as an input. Staff Cmnts. at 8-9. In addition, Staff cites to no legal basis for its claim that the information is required to make the plan capable of being audited, and ComEd is unaware of any audit requirement related to procurement plans. Finally, all of the costs ComEd incurs under Section 16-111.5B are reported in the annual reconciliation dockets required by ComEd's Rider EDA – Energy Efficiency and Demand Response Adjustment. Each year the Commission reviews the prudence and reasonableness of these costs together with the energy efficiency costs ComEd incurs under Section 8-103 of the PUA. ComEd Resp. at 7-8.

ComEd maintains that ample reporting and Commission review of all energy efficiency costs already exist, and Staff's proposal would not provide the Commission with any additional information relevant to the determinations to be made in this proceeding. ComEd Resp. at 8.

4. AG's Position

Staff asks for a Commission directive to require the utilities to report expected energy efficiency program costs in their IPA RFP submittals and, similarly, for the IPA to report these total costs in its Plan. The AG supports that request. Such a directive would improve the clarity and transparency in tracking and reporting energy efficiency costs, and should be adopted by the Commission. AG Resp. at 1-2.

5. Ameren's Position

Ameren states that it can see both sides of this issue and does not formally take a position, but opines that the IPA's rationale for arguing that the additional information should not be included in utility submittals or in the plan submitted to the Commission because it is not specifically required by Section 5/16-111.5B is troubling. The IPA acknowledges that the Commission has the authority to impose additional requirements, and the IPA itself regularly includes a host of information in its plan that is supplemental to the PUA's enumerated requirements. *See* 220 ILCS 5/16-111.5B(a)(2) and (a)(4). For example, the 2017 Plan includes considerably more than the bare minimum, in the form of IPA commentary on a variety of policy and legal matters. Ameren Rep. at 2-3.

With respect to reporting costs, however, the IPA seems to advocate for shielding the information Staff is requesting from the public, and to do so may hide from the public the true cost (albeit estimated) of the annual incremental energy efficiency procurement pursuant to Section 5/16-111.5B. Ameren explains that until last year, this was a non-issue, because the utilities were free to include non-program specific costs of the IPA procurement process in their TRC analyses, thereby ensuring that only those programs for which the total benefits actually outweighed the total costs of procurement were ultimately procured. But, at the urging of Staff and the IPA, the Commission decided in last year's procurement plan docket that so-called "fixed costs" cannot be included in the TRC analysis at the program level. *See 2016 Plan Docket*, Order at 95. There is no TRC analysis at the "portfolio level" for the IPA procurement, however, and, as a result, those "fixed" costs have been lost altogether. A ratepayer, therefore, could not ascertain when reviewing an IPA plan that there are additional costs to the procurement of the programs and measures set forth therein—costs which, counter-intuitively, are not accounted for in the "cost-effectiveness" analysis, and which, in close cases, could mean that the procurement of these programs actually costs the public more than the sum total of their benefits. Ameren Rep. at 3-4.

For its part, Staff's proposal is a commendable attempt to keep sight of those unaccounted-for costs, if not to involve them in the TRC analysis, and the IPA's opposition to granting the public that needed level of oversight and transparency is troubling, especially in light of last year's Order removing such costs from consideration when determining whether to approve a program in the first place. Ameren Rep. at 4.

6. IPA's Position

The IPA disagrees with Staff and notes that the specific requirements of utility energy efficiency assessments and procurement plans are detailed in the statute (*See* 220 ILCS 5/16-111.5B(a)(3)(A-G), 220 ILCS 5/16-111.5(b)(1-4)), and neither requires disclosure of these estimates. While the Commission certainly has authority to force parties' filings to include additional items beyond statutory requirements, the IPA believes it should not impose extra-statutory requirements without sound justification. IPA Resp. at 10.

In reviewing Staff's offered justifications, the IPA states that Staff concedes that this information is irrelevant to understanding the cost-effectiveness of individual energy efficiency programs proposed for approval. Further, Staff makes no argument that this information is: a) not available to it, b) not available to other parties, c) not otherwise reported through more appropriate proceedings or filings, or d) could not be reported by the utilities should they elect to do so. Instead, its thin rationale for a new, extra-statutory, prescriptive requirement is merely that the resulting Plan would be "transparent and auditable" without any explanation of who would "audit" the IPA's annual Plan and under what authority, let alone how requiring reporting of an estimate of expected utility administrative costs would aid in any audit process. And while the IPA agrees that transparency is generally a laudable goal, this requirement would not create transparency around known information; it would simply require the reporting of best guess estimates that may prove inaccurate, introducing potential confusion with little corresponding benefit. As a result, the IPA opines that Staff's proposal should be rejected. IPA Resp. at 10-11.

7. Commission Analysis and Conclusion

In approving the 2015 Plan, the Commission stated that:

> To the extent the utilities do not explicitly track this information already, the Commission hereby directs Ameren and ComEd to track administrative costs by program in order to aid in future determinations of appropriate administrative cost assumptions to use in the TRC analysis of the Section 16-111.5B programs.

2015 Plan Docket, Order at 224. In last year's proceeding, the Commission stated that:

> It seems that even after the Commission ordered the utilities to track their administrative costs in Docket No. 14-0588, the utilities are not clear as to what administrative costs should be tracked, and, as ComEd has noted, it is unclear what Staff proposes with respect to additional reporting and whether it is needed. These topics should be thoroughly addressed and determined with specificity in workshops conducted by the SAG.

2016 Plan Docket, Order at 95. The Commission has found that administrative costs need to be tracked, and there is nothing in this proceeding that leads the Commission to overturn that decision. The Commission agrees with Staff that the utilities' administrative costs are not only relevant to proceedings where the utilities seek to be reimbursed for these costs, but also relevant to determining whether the Section 16-111.5B programs reduce the overall cost of electricity for ratepayers. This is consistent with the Section 16-111.5B(a)(3)(D) requirement of an analysis showing that the new or expanded cost-effective energy efficiency programs or measures would lead to a reduction in the overall cost of electric service. 220 ILCS 5/16-111.5B(a)(3)(D).

The Commission adopts Staff's proposal and directs the utilities to report, and the IPA to include in its future plans, the total expected costs to be incurred for Section 16-111.B.

B. Section 9.3 2016 Workshop Consensus Items

1. Summary

Section 9.3 of the 2017 Plan includes a list of the specific consensus items agreed to by participants to the 2016 Section 16-111.5B Workshops. These items, taken from the 2016 SAG Report, are intended to update and replace consensus items previously approved by the Commission. As in the past, the IPA requests that the Commission expressly approve the consensus items to be binding upon the energy efficiency programs approved as part of the IPA's 2017 Plan for the planning of, implementation of, reporting on, and evaluation, measurement and verification of savings achieved by such programs, as well as binding upon parties up to the development of the IPA's 2018 Procurement Plan (at which time any changes to the list may be considered). 2017 Plan at 107.

2. Ameren's Position

Ameren agrees that the consensus items from the 2016 SAG Report from the workshops should be adopted by the Commission. That said, Ameren asserts that the 2017 Plan should remove all doubt and be clear that all of the consensus language reached by the stakeholders (after many hours of meetings and a substantial amount of work) is being approved by the Commission. The IPA has included language in Section 9.3 that is apparently intended to accomplish that goal. Ameren argues that the IPA's commentary elsewhere continues to suggest that it believes some of the consensus language reached by the SAG in the workshop process does not apply at all, or at least does not apply to the IPA, despite the IPA's participation in the process. Ameren Cmnts. at 3.

Ameren suggests that the IPA's selective highlighting of consensus items has allowed the IPA to assume that the consensus language which it has not highlighted does not apply to or bind the IPA. Ameren therefore requests that the Commission order the IPA either to incorporate all of the consensus language from the 2016 SAG Report into the 2017 Plan itself, or to incorporate none of it and simply make clear in the Order that all of the consensus language in 2016 SAG Report is approved by the Commission, so that it is abundantly clear that the various consensus items and language are on equal footing and are universally approved. The IPA has agreed to the second approach, and Ameren recommends that the Commission order the IPA to modify its Plan accordingly. IPA Resp. at 11-12. Ameren Rep. at 4.

Ameren maintains that there is no present disagreement about any duplicative program determinations in this docket, something the IPA readily acknowledges, and the contents of Ameren's Plan 4 have been agreed to by stipulation in Docket No. 16-0413. Equally important, next year's IPA procurement process will not deal with the same problems regarding misalignment of the Sections 8-103 and 16-111.5B planning processes, as all of Ameren's Section 8-103 programs will be known and identified in the RFP, and this issue therefore does not require extended Commission attention at this time. Ameren Rep. at 6-7.

3. Staff's Position

Staff agrees that the Commission should adopt the 2016 Section 16-111.5B energy efficiency Consensus Items set forth in the 2016 SAG Report. Staff recommends that the Commission explicitly approve the broadly applicable Section 16-111.5B consensus language from the 2016 SAG Workshop Report that continues to be relevant beyond this docket and that is not reproduced in Section 9.3 of the Plan. Staff Cmnts. at 10-11.

4. NRDC's Position

NRDC explains that part of the consensus language not included in Section 9.3 of the 2017 Plan says that "for third-party programs that would duplicate programs Ameren Illinois plans to propose for inclusion in its 8-103 / 8-104 Plan, Ameren Illinois may request the potentially duplicative program only be conditionally approved…" NRDC submits that the key phrase in this statement is "plans to propose." That implies that a decision has been made by Ameren to include a particular type of program in its Section 8-103 portfolio at the time the IPA RFP was issued, and that such an intention would be made clear to prospective bidders. NRDC states that such determinations would be made in an integrated planning process – ideally collaboratively between the utility and other stakeholders, as occurred this year with Com Ed – with the outcome being clarity on which types of programs would be included solely in a Section 8-103 portfolio, solely in the IPA procurement portfolio, or in both. In such cases, NRDC would have no problem with a similar program bid into the IPA being only conditionally accepted by the Commission (with the condition being that it proceeds only if the Ameren Section 8-103 program proposal is rejected or if a determination is made that an expansion of the Section 8-103 effort could be accommodated by the market). However, Ameren appears to be asking for the ability to decide to include a program in its proposed Section 8-103 portfolio long after IPA bids have been received and reviewed and to then render such IPA bids "duplicative" after the fact. That ability is not consistent with a reasonable read of the consensus language cited. If that were the intent of the language, NRDC would not support it as part of a consensus agreement. NRDC Resp. at 6-7.

5. IPA's Position

The IPA states that its listing of consensus items was copied directly from the 2016 SAG Report. *See* 2016 SAG Report at 21-24. Ameren suggests either: 1) incorporating all consensus language contained in the 2016 SAG Report in the 2017 Plan itself; or 2) including no such language, but simply making clear that all consensus language in is approved by the Commission. Ameren Cmnts. at 5. The IPA believes that its current approach is sound, and no party contests that approval of the Plan as drafted would not result in Commission approval of all consensus language contained in the 2016 SAG Report. However, in the interest of reducing contested issues, the IPA would prefer, and agrees to, Ameren's second proposed approach. While not substantively problematic, the IPA believes that the volume of new language folded in through the first approach would make the 2017 Plan less focused and more unwieldly and thus should be avoided. IPA Resp. at 11.

6. Commission Analysis and Conclusion

All parties seem to agree that it is appropriate that the specific consensus items be included in the 2017 Plan. The Commission adopts Ameren's second proposal and explicitly approves all the consensus language contained in Appendix H to the 2017 Plan – the 2016 SAG Report.

Also, due to the stipulation reached in Ameren's Section 8-103 proceeding, Docket No. 16-0413, there are no outstanding issues relating to the interaction of the two energy efficiency portfolios.

C. Section 9.4.1 Scale of Section 16-111.5B Programs

1. Summary

Section 9.4.1 of the 2017 Plan opines that the size of the Section 16-111.5B programs may have peaked in the 2016-2017 delivery year. It states that this phenomenon is unexpected because bidders continue to become more familiar with the Section 16-111.5B process and this year's RFP offered programs for three years in length. 2017 Plan at 111.

The 2017 Plan suggests that one possible explanation is that this peak in size could constitute an accurate reflection of the market for energy efficiency in Illinois. Another possible explanation is that this could be an indicator of barriers to participation by potential bidders. The 2017 Plan continues with various suggestions for improving the process, including that the utilities could: 1) conduct more extensive outreach to disseminate the RFPs in order to find new potential bidders; or 2) use the potential studies required under Section 16-111.5B(a)(3)(A) (and perhaps other screening tools) to specifically solicit new programs that are not part of the approved Section 16-111.5B and 8-103 suite of programs. 2017 Plan at 111.

The 2017 Plan recommends that the best solution for ensuring that the RFP process is able to "fully capture the potential for all achievable cost-effective savings, to the extent practicable" as required by the law would be for the Commission to: a) require SAG workshops shortly after the conclusion of the proceeding approving the 2017 Plan at which the utilities and stakeholders can discuss more effective strategies for marketing Section 16-111.5B RFPs and b) require that the utilities' potential studies and stakeholder feedback be utilized in ensuring that the RFPs, while remaining open-ended, specifically identify any program areas for which bids should be actively sought. 2017 Plan at 111.

2. AG's Position

The AG concurs with the IPA that utilities could conduct more extensive outreach to disseminate the RFPs in order to find new potential bidders and urges the Commission to require that the 2018 procurement process reflect the consensus of these discussions in improving efforts at disseminating the RFP – particularly if smaller, less-nationally established companies are to compete in the bid process. AG Cmnts. at 2-3.

The AG also supports a Commission finding that utilities be directed to include in the Section 16-111.5B RFP process specific solicitations for programs that reflect the findings of the potential studies required under Section 16-111.5B(a)(3)(A) of the PUA. While the IPA notes that such an effort might solicit "new" programs, the AG suggests that another result might be bids for expansions of programs that compete in a cost-effective manner with existing utility programs that reflect the identified potential in the market. The AG concurs with the IPA's acknowledgement that "[t]hese studies are extensive and paid for by ratepayers, and often yield rich information regarding potential energy efficiency program opportunities." 2017 Plan at 111; AG Cmnts. at 3.

The AG urges the Commission to adopt these as specific findings, both to ensure that cost-effective opportunities for energy efficiency are not being left on the table and to ensure the cost-effectiveness of required potential studies. AG Cmnts. at 3.

The Commission should ensure that the time and attention stakeholders, utilities and the IPA expend on analyzing the issue through the workshop process, if so ordered, has some consequence. The Commission should endorse the AG's request that any consensus reached in workshops held to address the breadth of participation issue be reflected in the 2018 RFP procurement process. AG Rep. at 2.

3. Ameren's Position

Ameren submits that there are several reasons why incremental energy efficiency programs appear to be smaller this year, and that this new development may in fact mean the process is working exactly as designed—not that it is broken, as the IPA appears to suggest. However, in an effort to minimize the contested issues in this docket, Ameren does not object to the IPA's proposal that the Commission: (a) require SAG workshops after the conclusion of the proceeding approving the 2017 Plan, at which the utilities and stakeholders can discuss more effective strategies for marketing Section 16-111.5B RFPs; and (b) require that the utilities' potential studies and stakeholder feedback be utilized in ensuring that the RFPs, while remaining open-ended, specifically identify any program areas for which bids should be actively sought. *See* 2017 Plan at 111. As long as the Commission's directive leaves the utilities the flexibility contemplated by the IPA, Ameren believes this approach is workable. Indeed, Ameren already provides specific direction to bidders based on the Potential Study and the larger energy efficiency environment in Illinois—for example, this year Ameren provided specific details in its RFP regarding the interplay between Sections 16-111.5B, 8-103, and 8-104—and does not object to continuing to do so in appropriate contexts in the future. Ameren further agrees that the details are best addressed in workshops and that the results of those workshops, if consensus is reached, can be incorporated into the RFP for the next IPA Plan. Ameren Cmnts. at 6-7.

Ameren also cautions that the timeframe available for the parties to reach consensus is necessarily limited by the PUA, which requires Ameren to provide its submittal to the IPA on July 15. Practically speaking, Ameren must issue its RFP several months prior to that date in order to perform the necessary analysis and include the stakeholders in the process before the deadline. To the extent no "consensus" is reached in workshops prior to the time at which Ameren must issue its RFP, Ameren will make a good faith attempt to accomplish what the IPA suggests. Ameren Rep. at 7.

4. ComEd's Position

ComEd agrees with the IPA's proposal to further explore this issue through workshops. Like Ameren, moreover, ComEd already provides bidders access to its Potential Study, and thus it is unclear how the second part of the IPA's recommendation would further enhance the existing process. To narrow the issues in this docket, ComEd does not object to discussions within workshops of how to continue to utilize the potential studies, and welcomes the opportunity to discuss these issues further. ComEd Resp. at 6.

5. Commission Analysis and Conclusion

The Commission is also concerned with the IPA's observation that the size of the Section 16-111.5B programs may have peaked in the 2016-2017 delivery year. The Commission encourages greater utilization of the utilities' potential studies to reach previously unserved markets. The 2017 Plan recommends that the best solution for ensuring that the RFP process is able to "fully capture the potential for all achievable cost-effective savings, to the extent practicable" as required by the law would be for the Commission to: a) require SAG workshops shortly after the conclusion of the proceeding approving the 2017 Plan at which the utilities and stakeholders can discuss more effective strategies for marketing Section 16-111.5B RFPs; and b) require that the utilities' potential studies and stakeholder feedback be utilized in ensuring that the RFPs, while remaining open-ended, specifically identify any program areas for which bids should be actively sought.

The Commission sees that no party objects to these proposals, and they are adopted. The Commission agrees with Ameren that time constraints may limit the ability of parties to reach a consensus. To the extent consensus is reached, it should be implemented by the utilities in their RFPs.

D. Section 9.4.2 Improving/Refining Bids

1. Summary

Section 9.4.2 of the 2017 Plan states that there are several potential refinements to the RFP process that could improve the bids received. It notes that concerns have been raised that the nature of the Section 16-111.5B RFP process could allow bidders to propose programs with excessive administration costs by finding headroom in the TRC analysis. Likewise, another concern that has been expressed is a desire for more post-bid negotiations between the utilities and bidders in order to refine/improve the scope, scale, price, etc., of bids. Both concepts suggest that there could be potential to move away from a process where only minor adjustments are made to bids (e.g., adjusting incorrect savings levels provided by bidders) to a model where active negotiations are undertaken in order to improve the quality and value to ratepayers of the proposed programs. 2017 Plan at 111.

According to the 2017 Plan, however, post-bid negotiations, could create significant challenges to successful implementation. With the requirement that the utilities provide an assessment of the bids to the IPA by July 15 of each year, there is limited time available for utilities to undertake such negotiations after a bid is received. Further, the IPA fears that bidders could use a negotiation process as an opportunity to change an initially submitted proposal into something fundamentally different and less connected to the bidder's actual capacity just to attain program approval. Worse still, that dynamic could eventually result in proposed initial program designs which reflect a bidder's best-case scenario, submitted under the understanding that should the utilities or others be uncomfortable with assumptions made in that proposal (or should that initial proposal fail the TRC), there exists room for negotiation. 2017 Plan at 111.

Based upon the IPA's experience with its other procurements (e.g., block energy, capacity, renewables), the 2017 Plan states that the best mechanism for driving bidders to produce the most honest and accurate proposals, oriented around minimizing costs and maximizing benefits, may instead be through having clear and explicit processes and rules, and increased participation to encourage competition between bidders. That approach can drive positive results even if a bid's proposed terms are fixed. Such improvements could perhaps be achieved through improvements to the RFP process, although the IPA acknowledges that not every potential third-party energy efficiency program features a cadre of capable bidders equipped to compete. Nevertheless, the 2017 Plan notes that further examination of this issue may be warranted, but does not recommend requiring a post-bid negotiation process at this time. 2017 Plan at 112.

The 2017 Plan observes that bidders have very rarely participated in the comment process on draft plans or the docketed plan approval proceedings before the

Commission. The IPA's proposed solution calls for communications to bidders to clarify that they have the right to participate in either the comment process or the docketed proceeding, and that such participation will not prejudice the evaluation of their bid. 2017 Plan at 112.

According to the 2017 Plan, the use of pay for performance contracts, holdbacks, and surety bonds has been the way in which the utilities have addressed the risk of programs not achieving savings goals. Unlike Section 8-103 programs (featuring goals developed by the utilities), savings goals for Section 16-111.5B programs are proposed by the bidders. While many programs have performed successfully, other programs have been less successful, and in one case, as extensively litigated in Docket No. 14-0567, a vendor bankruptcy led to costs incurred that did not result in any energy savings. *Ill. Commerce Comm'n On Its Own Motion*, Docket No. 14-0567, Order (June 21, 2016). The 2017 Plan states that while the IPA appreciates that the Commission must consider whether utilities prudently manage their expenditures, balance must be achieved between necessary risks to achieve cost-effective energy reductions and completely insulating ratepayers or shareholders from any lost expenses. 2017 Plan at 112.

One suggestion for achieving this balance could be general guidance from the Commission about terms and conditions utilities should include in their contracts offered to vendors, as such clarity could also increase vendor confidence in the program structure. While the IPA is not seeking to litigate each and every utility energy efficiency contract term through a 90-day proceeding addressing a host of other, non-energy efficiency issues, the Plan approval process may allow for general Commission guidance and any specific, discrete questions about contract terms (such as the propriety of surety bonds) to be addressed. 2017 Plan at 112.

This Section of the 2017 Plan also contains a brief discussion of Ameren's treatment of gas savings.

2. AG's Position

The AG notes that in the *2016 Plan Docket* the Commission specifically required the utilities to develop a plan to ensure that Section 16-111.5B contracts receive the same level of scrutiny as Section 8-103 contracts in terms of minimizing costs to the ratepayer and maximizing energy savings achieved. The Commission's Order stated:

> It seems to be a simple matter to require the same level of scrutiny for Section 16-111.5B contracts as that which is imposed for Section 8-103 contracts. The utilities are directed to develop a plan to implement use of the same scrutiny for Section 16-111.5B contracts as that for Section 8-103 contracts through workshops conducted by the SAG.

2016 Plan Docket at 110. The 2017 Plan recognizes the potential impact on ratepayer costs and savings achieved in acknowledging the gray area that exists in IPA energy efficiency bids between a bid that passes the cost-effectiveness test of Section 16-111.5B but likewise allows for "bidders to propose programs with excessive administration costs by finding headroom in the TRC analysis." 2017 Plan at 111. The fact is neither utility developed the plan requested by the Commission to ensure equivalent contract scrutiny. AG Cmnts. at 3-5.

The AG states that, for example, as noted in the 2016 SAG Report, while each utility appears to attempt to clarify uncertain terms with a bidder, no effort is made to negotiate prices or improve savings performance projections either before or after submission of the RFP responses to the IPA. On the other hand, the utilities verified during the IPA workshop sessions that discussions related to improving savings and/or budget terms are common practice for Section 8-103 contracts. The Facilitator's Report states:

> Section 8-103 contracts between utilities and vendors include general conditions, price, holdback, savings, and implementation details. Utilities negotiate contract terms to ensure high-quality, well-priced programs.

See 2016 SAG Report at 19; AG Cmnts. at 5.

The AG argues that the bottom line is that the IPA programs, both in terms of the statutory intent of enabling "expansions" of Section 8-103 program and in terms of the costs, which are charged to ratepayers via the same rider that recovers costs for Section 8-103 programs, should not be treated differently by the utilities for purposes of ensuring maximum energy savings delivered at the least cost to ratepayers than those secured under Section 8-103 contract provisions. These programs, whether delivered as a result of Section 16-111.5B procurements or through Section 8-103 requirements, are still subject to the least cost provisions of the PUA. The AG continues that those provisions mandate that utility service – which clearly includes the provision of ratepayer-funded energy efficiency programs – shall be least cost. *See* 220 ILCS 5/8-401 ("Every public utility subject to this Act shall provide service and facilities which are in all respects adequate, efficient, reliable and environmentally safe and which, consistent with these obligations, constitute the least-cost means of meeting the utility's service obligations."); *see also* 220 ILCS 5/1-102 ("The General Assembly finds that the health, welfare and prosperity of all Illinois citizens require the provision of adequate, efficient, reliable, environmentally safe and least-cost public utility services at prices which accurately reflect the long-term cost of such services and which are equitable to all citizens."); AG Cmnts. at 5-6.

The AG reasons that in order to ensure that the utilities apply the same scrutiny to IPA contracts as Section 8-103 contracts, the Commission should order the utilities to include, in their RFPs, notice to vendors that the utilities shall, after Commission approval of a program that passes the TRC and performance risk criteria and as a condition of the contracting process: (1) scrutinize the cost per kilowatt hour saved to ensure that the price, while passing the TRC, is not inflated and if necessary, negotiate a reduced cost consistent with the Utility's Section 8-103 contracting practices; and (2) scrutinize the implementation strategy and program design, including the energy efficiency measure mix, to ensure that the program is consistent with best practices. All modifications to the programs and forecasted costs should be reported to the Commission prior to the start date of the 2017 Plan. The AG submits that the Commission should ensure that these programs are as cost-effective as the programs approved under Section 8-103 of the

PUA. Ratepayers pay for both these programs through the single energy efficiency rider. There should be no difference in Commission, utility or ratepayer expectations that the programs that are being financed by utility customers are worth the dollars spent and indeed cheaper than the cost of energy supply. The AG states that all modifications to the programs and forecasted costs should be reported to the Commission prior to the start date of the 2017 Plan. AG Resp. at 6-7.

The AG notes that Ameren suggests that this topic could, again, be discussed further in workshops, and that no specific finding be issued by the Commission on this point in this docket. Ameren Cmnts. at 8. The AG offers that this, however, was precisely the procedure approved in last year's docket, with no resolution achieved, despite the Commission's clear finding that the utilities should develop a plan to ensure that the IPA contract process mirrors the Section 8-103 process in terms of vigor and scrutiny. The utilities have presented no evidence in this docket why that directive cannot be achieved. AG Resp. at 6-7.

According to the AG, it is asking the Commission to uphold the finding it made last year that would require the Companies to negotiate the contracts for best practices and cost and savings with the same level of scrutiny applied to Section 8-103 contracts. *2016 Plan Docket*, Order at 110. Ameren's claim that such a directive is unworkable rings hollow. The Utilities could make clear in the RFPs that final terms would be subject to negotiation to ensure that ratepayers who finance the programs are assured of the same diligence in reviewing contract terms that the utilities apply to their Section 8-103 programs. AG Rep. at 4. The AG states, moreover, that there is a difference between evaluating the cost-effectiveness of a proposed program, as Section 16-111.5B requires, and finalizing a contract to ensure that ratepayers receive a quality program. For example, if a program incents CFLs – a measure that is barely cost-effective due to changing lighting standards and market price reductions – the utility should be able to go back to the vendor and suggest that the bid be modified to incent LED bulbs. Another possible solution is that an implementation strategy for an otherwise cost-effective program could be modified to better serve customers. It is the AG's opinion that these are areas in which the utilities are in a position to improve both the content and cost of a program. AG Rep. at 5.

The AG indicates that Ameren further claims that the AG's request is inconsistent with the AG's criticism of Ameren's practice of employing surety bonds and holdback provisions. The AG explains that it raised those points because, both Ameren and ComEd currently employ significantly different pay-for-performance contract provisions. Ameren requires a surety bond, but ComEd does not and ComEd's holdback provisions are significantly higher than Ameren's. The AG notes that the IPA also expressed its frustration on this point, stating that it had no evidence as to what struck the right balance of protecting ratepayers and not foreclosing vendors from participating in the bid process. The AG adds that it urged the Commission to seek specific evidence in this proceeding on what constitutes the right balance of protecting ratepayer interests in funding only quality, cost-effective programs and not making contract provisions so severe that smaller bidders are discouraged from participating in the bidding process, but the decision was made that no hearings were necessary. The AG contends that the point raised on these inconsistencies is a separate issue, and should not be tied to the lesser scrutiny applied to IPA program contracts issue. AG Rep. at 5.

The AG asserts that the Commission should again require the parties to explore these issues in workshops. Ameren should be required to explain why it believes a surety bond is necessary. ComEd should detail why it believes the significant holdback provisions it employs achieve the right balance of encouraging broad vendor participation and ratepayer protections. Consensus agreements reached in additional workshops should be applied to the 2018 IPA Procurement Plan. Discussion of Section 8-103 contracting practices and how they can or cannot be applied to IPA contract negotiations should also be an agenda item. The AG emphasizes that such Commission direction is essential to ensuring that ratepayers are not paying more than they should for an energy efficiency program, are adequately protected from poor program designs, and that smaller potential vendors are not unfairly shut out of the bid process before it begins. AG Rep. at 6.

The AG notes that in Section 9.4.2 the IPA also discusses various, differing contract requirements for Section 16-111.5B programs that are purported to achieve the goal of striking the required balance between protecting ratepayer interests in not paying for programs that fail to achieve forecasted goals on the one hand, and ensuring that contract requirements are not so strict as to limit the ability of smaller-sized vendors from submitting bids in response to the Utilities' RFPs on the other. 2017 Plan at 111-113. AG Cmnts. at 7-8.

The AG notes that ComEd urges the Commission to provide its imprimatur on the actual contracting approaches and provisions used by ComEd this year for both third party bidders and its own implementers, provisions which ComEd admits were revised and made more stringent this year following the Commission's disallowance in a ComEd energy efficiency rider reconciliation docket, Docket No. 14-0567, of certain start-up costs paid to a third-party IPA vendor that eventually declared bankruptcy. The AG points out that the Commission never provided specific direction in its Docket No. 14-0567 Order as to what ideal contract terms look like. Indeed, the 2016 SAG Report documents the fact that Ameren and ComEd employ different contracting terms with IPA vendors. AG Resp. at 4.

While the AG appreciates ComEd's desire to gain certainty on contract terms the Commission views will both protect ratepayers and ComEd shareholders, this is not the docket to accomplish that if specific evidence and hearings are not conducted. ComEd's discussion of its contract terms, while informative, does not provide the Commission with evidence as to why these particular terms achieve the appropriate balance of: (1) protecting ratepayers from paying for programs from ineffective vendors, (2) ensuring bidders are not dissuaded from participating in the IPA bidding process because the terms are too draconian (particularly for smaller, local bidders); and (3) avoiding unnecessarily higher-priced bids from bidders who are able to meet ComEd's/Ameren's contract terms, but are forced to recoup the costs of meeting these terms in the bid prices. The AG maintains that this record lacks specific evidence on what constitute reasonable, third-party contract terms. AG Resp. at 4-5.

Given the October 5, 2016 decision not to hold hearings, the AG suggests that the Commission require the IPA, the utilities and stakeholders to specifically explore this issue through the SAG IPA Workshop process. The discussion should include input from the utilities, stakeholder experts, and other fact-based resources. AG Resp. at 5.

3. Ameren's Position

Ameren appreciates that the IPA has identified what it believes to be improvements to the process, and that the IPA is not seeking a Commission directive regarding any of its suggestions. But Ameren respectfully requests that the Commission make clear that the IPA's proposals on this point are just proposals, and that those proposals could be addressed at the SAG workshop series to be convened in response to the IPA's proposal in Section 9.4.1. Issues like these are best reviewed in the workshop context, where the stakeholders can consider all of the relevant facts and circumstances in a collaborative environment, rather than in an expedited approval docket. Ameren Cmnts. at 8.

Ameren opines that the AG appears to confuse the Commission's directive that the utilities apply the same level of scrutiny to Section 16-111.5B contracts as to Section 8-103 contracts for a directive that the utilities employ the exact same process for scrutinizing bids in both contexts. Ameren explains that there are different statutory considerations at play when scrutinizing programs to be run under Section 16-111.5B and programs to be run under Section 8-103. For example, Section 16-111.5B programs and measures are, by law, subject to many different layers of scrutiny which are actually more exacting than those applied to Section 8-103 programs, such as (1) an analysis showing that the new or expanded cost-effective energy efficiency programs or measures would lead to a reduction in the overall cost of electric service (220 ILCS 5/16-111.5B(a)(3)(D)), and (2) an analysis of how the cost of procuring additional cost-effective energy efficiency measures compares over the life of the measures to the prevailing cost of comparable supply (220 ILCS 5/16-111.5B(a)(3)(E)). Ameren offers that Section 16-111.5B programs are subject to these additional layers of scrutiny for good reason - the PUA does not contain the same ratepayer protections with respect to the cost of the IPA's incremental energy efficiency procurement that it does with respect to Section 8-103. Specifically, there is no IPA corollary for the Section 8-103(d) tool capping the estimated annual rate increases associated with energy efficiency program and measures. Ameren states that the process cannot be the same, and consistent with the law, the Commission did not direct that it should be. Ameren Resp. at 6.

Also, Ameren suggests that the AG appears to confuse scrutiny of contracts, which is what the Commission referred to in last year's Order (*2016 Plan Docket*, Order at 110), with scrutiny of future performance. The AG is demanding, in part, that the utilities "scrutinize the implementation strategy and program design, including the energy efficiency measure mix, to ensure that the program is consistent with best practices." AG Cmnts. at 7. But the AG has provided no evidence that utilities do not already scrutinize bids or work with bidders to correct bids that are not, on their face, correct in light of prevailing standards like the Illinois Technical Reference Manual. In fact, Ameren already does exactly that. *See* Ameren Submittal at 14 (located at IPA's Petition/Application (PART 1), Attachment 7 (September 27, 2016)). During the bid review process, Ameren's consultant, AEG, reviewed the detailed savings calculations provided by the bidders and then independently calculated savings for each individual measure to verify compliance with technical resource manual ("TRM") Version 5.0 where an TRM equation was applicable. If the results matched, compliance was verified. If AEG found minor discrepancies, AEG adjusted the savings so they were in compliance. If there were major discrepancies, AEG went back to the bidder to understand why there were differences between the bidder's savings calculations and AEG's savings calculations. In all but one case, the issues were resolved and AEG was able to verify correct application of TRM algorithms where applicable. In the one unresolved case, the AEG independently calculated savings values were utilized. Ameren Submittal at 14; Ameren Resp. at 6-7.

Ameren avers that there is no problem that needs to be addressed, and the AG has failed to identify a single instance in which the problem of which it complains—vendors claiming additional costs to fill the "headroom" of the TRC analysis either before or after their programs have been approved—has actually occurred. Indeed, it is hard to imagine how that could occur before the program is approved, given that the utilities (and the IPA) run the TRC after the bid, complete with estimated program costs, has already been submitted. And there simply is no opportunity for vendors to suddenly balloon the administrative costs of their program during the contracting stage, when it has already been approved. On a related note, one way that Ameren ensures vendors do not have the ability to "game" the TRC analysis is by keeping Ameren's avoided costs—a critical component of the TRC analysis—private, a practice which the AG inexplicably attacks in this docket (while at the same time maintaining that information the AG seeks to rely upon for its positions should be kept "confidential"). Ameren Rep. at 9-10.

Ameren argues, moreover, that the AG does not provide any explanation of how the vague directive it seeks could be implemented in a manner consistent with the law. Given the tight timeframe that is allowed for in the PUA for the procurement process, the AG's proposal would be unworkable in practice because Ameren has no control over when or how the bidders, who put together a bid they believe will be profitable for them, will react. Ameren Resp. at 7.

Ameren opines that the AG's position is contradicted by its own assertions. The AG incorrectly holds up language from the 2016 SAG Report as an exemplar of what Ameren does do for Section 8-103 programs but does not do for Section 16-111.5B. Yet, elsewhere in its filing, the AG criticizes Ameren for employing holdbacks and surety bonds - measures designed to "ensure high-quality, well-priced programs" - in its Section 16-111.5B contracts, claiming without any cited evidence that "[u]pon information and belief, some local vendors of limited size have complained about their inability to compete against larger, national vendors who have the ability to absorb high priced surety bonds or extensive holdback provisions." AG Cmnts. at 8. This is an inconsistency, and is likely due to the fact that the AG's position is replete with generalities and very few specifics. Ameren asserts that the AG cannot demand greater scrutiny of Section 16-111.5B contracts while simultaneously demanding lesser scrutiny of Section 16-111.5B bids on the exact same issues. Ameren Resp. at 7-8. For the foregoing reasons, the AG's unsupported demand regarding "equal scrutiny" should be rejected by the Commission. Ameren Rep. at 11.

Ameren notes that the AG appears to be concerned about the severity of contract terms. AG Cmnts. at 8-9. The measures are Ameren's employment of a holdback of five percent, subject to final evaluation results and Ameren's requirement that vendors obtain a surety bond for twenty-five percent of the annual contract cost. Ameren Resp. at 8-9. While the AG lumps holdbacks and surety bonds together, Ameren maintains that it is important to note the distinction between these two measures of protection and the purposes they serve. Ameren requires surety bonds to ensure that a vendor has the ability to return dollars to Ameren customers if actual savings, as determined by the independent evaluator, are less than the savings reported by the implementer. Implementers receive payment as they report savings. At the end of the implementation period, evaluators verify that the number of installed measures has been accurately reported. Evaluators also verify that implementers have correctly calculated the amount of savings for each measure installed. Finally, evaluators confirm that the correct measures were installed to eligible customers. Ameren explains that the surety bond is set at a reasonable level (25% of the program cost) that balances risk versus decreased participation by vendors. This avoids a scenario where the customers - or the utility - are left on the hook for a vendor's intentional or unintentional over-reporting of savings, particularly in situations of vendor insolvency. Ameren states that the Commission recently addressed this issue in an energy efficiency reconciliation docket, so this concern is both timely and supported by actual evidence. *See* Docket No. 14-0567, Order at 25; Ameren Resp. at 9.

Ameren explains that holdbacks, on the other hand, are not a method to return funds to ratepayers. Holdbacks are designed to encourage implementers to deliver the entire amount of the savings as promised in their bid. Implementers that fail to achieve at least 95% of their contractual commitment are subject to losing some or all of the 5% holdback. This important contract term ensures that bids do not include unrealistic savings targets and that there is a reasonable level of certainty that planned savings will be achieved. Ameren Resp. at 9.

In any event, Ameren adds that the AG has claimed "[u]pon information and belief" that these contract terms are suppressing bidder participation. Ameren opines that the Commission and the parties have too many legitimate issues to resolve in this docket to spend additional time addressing speculative arguments that have no evidentiary support. Moreover, it remains surprising to Ameren that the AG would not advocate for ratepayer protections like holdbacks or surety bonds, particularly given the Commission's recent guidance on the issue. *See* Docket No. 14-0567, Order at 25. The AG should be joining the Commission and the utilities in trying to maximize ratepayer protections, instead of casting the issue aside in the name of procuring energy efficiency. Ameren Resp. at 10.

Ameren notes that Staff requests that the Commission direct the non-financially interested SAG parties to address ways in which the bid review process could be refined to insulate both the utilities and ratepayers from performance risks. Staff Cmnts. at 20-21. In particular, Staff suggests that the past performance threshold - the amount of projected savings which a vendor must have actually achieved in a prior year in order to qualify for bid consideration in a later year - could be raised substantially from 5% in order to encourage bidders to bid realistic savings estimates. Ameren agrees with Staff (and notes that the use of the 5% holdback is recognized by Staff to be a useful tool in protecting ratepayers) and further agrees that this issue should be the subject of workshops in the next IPA plan cycle (i.e., after the Commission issues its Order in this docket). Ameren Resp. at 10-11.

Ameren states that it does not object to the relief requested by ComEd through its contract templates and would welcome Commission guidance on acceptable contract terms for IPA vendors. That said, Ameren respectfully requests that the Commission make clear, if necessary, that ComEd's form contracts are just one acceptable form of agreement, not the only acceptable form of agreement. Ameren Resp. at 10. Also, Ameren does not object to workshops designed to better understand the issues raised by the AG and Staff, provided that the parties actually adhere to the agreements reached through the workshop process. Ameren Rep. at 8-9.

4. ComEd's Position

ComEd notes that in response to the Commission's discussion concerning vendor contracting in the *2016 Plan Docket*, the utilities and stakeholders took up this issue in the workshop process held from January through July of 2016 together with a host of other issues. 2017 Plan at 106; AG Cmnts. at 3-4. Although this issue was not fully resolved during this compressed timeframe, the 2017 Plan notes that further Commission guidance is not necessary at this time. 2017 Plan at 106. ComEd argues that the AG proposes to short circuit the parties' discussions, however, and define in its Comments what the "same level of scrutiny" means. AG Cmnts. at 4. ComEd avers that this proposal should be rejected. ComEd Resp. at 4.

Importantly, ComEd states, the Order in the *2016 Plan Docket* rejected Staff's proposed changes to the third-party vendor contracting provisions, it directed the parties to instead focus on the level of scrutiny applied to the vendor contracts used under Sections 8-103 and 16-111.5B of the PUA. *2016 Plan Docket*, Order at 110. Six months later, however, the Commission went on to disallow costs associated with an underperforming vendor because ComEd had not withheld payment from the vendor, which now called into question the very contract terms that had been acceptable just six months earlier. Docket No. 14-0567, Order at 29-30. Because the Order in Docket No. 14-0567 was entered in late June of 2016, very little time remained in the workshop process to address these issues. ComEd Resp. at 5.

ComEd avers that the issue of the "level of scrutiny" has not been ignored by either the utilities or stakeholders, and has been the subject of much discussion in the workshop process. Even so, the resolution of the issue has been complicated by the unanticipated confusion and uncertainty surrounding the contracts themselves, the appropriate terms of which are now in doubt. As evidenced by the contract templates attached to ComEd's Comments, ComEd has long utilized different contract structures depending on whether the energy efficiency program is managed by ComEd or by a third-party vendor, and the pay-for-performance contracts in particular reflect a more stringent approach in light of the Plan Year 6 Reconciliation Order. *See* ComEd Cmnts., Apps. B-F. ComEd asserts that it is critical that the Commission first review and approve the contracts to be used under Sections 8-103 and 16-111.5B so that stakeholders can proceed with reaching consensus on the "level of scrutiny" to be applied to these contracts. Once those contracts are approved, the stakeholders will be able to more clearly and effectively discuss what it means to apply the same "level" of scrutiny to these different contract structures. ComEd Resp. at 5-6.

Importantly, the IPA appears to share ComEd's view that the issue of contract terms and conditions is the more pressing issue to be decided at this time and further cautions that the AG's proposal could actually trigger a chilling effect on vendor participation. *See* IPA Resp. at 12-13; ComEd Rep. at 9. For these reasons, ComEd requests that the Commission reject the AG's proposal regarding "the level of scrutiny," and instead direct the parties to resume discussions of this issue in workshops, which would greatly benefit from further Commission guidance regarding the appropriate contract terms and conditions. ComEd Rep. at 10.

ComEd appreciates the 2017 Plan's thoughtful and important discussion regarding the ongoing issues associated with third-party energy efficiency programs and pay-for-performance contracts. During last year's *2016 Plan Docket* proceeding, the parties addressed issues associated with underperforming third-party vendors, which was prompted by Staff's proposed disallowance in a separate docket (Docket No. 14-0567) regarding costs associated with an IPA energy efficiency program vendor that unexpectedly became insolvent. While Staff proposed that utilities withhold payment from the vendors until final evaluation results are known, the IPA, ComEd, and others cautioned that this approach could limit vendors' participation in IPA energy efficiency programs. Indeed, evaluation results can take years to finalize, which would leave the vendors without payment during this time. ComEd notes that in its Order in the *2016 Plan Docket*, the Commission rejected "Staff's proposals to require the utility to withhold payment and to disallow under-performing programs," and instead directed that interested parties further address contract issues through the workshop process facilitated by SAG. *2016 Plan Docket*, Order at 110. As the 2017 Plan observes, however, the Commission disallowed costs associated with the insolvent vendor just six months later because ComEd had not withheld payment from the vendor. Docket No. 14-0567, Order at 29-30; ComEd Cmnts. at 2-3.

ComEd notes that in light of the concerns previously articulated by the IPA, ComEd, and others regarding the undesirable impacts of Staff's withholding proposal on IPA energy efficiency programs and vendor participation, the 2017 Plan includes a discussion of the utilities' actions in response to these orders and a preliminary analysis of the impacts of these actions. Specifically, the 2017 Plan notes that ComEd and Ameren have revised their pay-for-performance contracting approaches to impose the more stringent payment terms recommended by the Commission. Ameren introduced a surety bond requirement for winning bidders, and the 2017 Plan questions whether this new requirement could have played a role in the decline in the number of bids Ameren received as compared to the prior year. With respect to ComEd, the 2017 Plan correctly observes that "ComEd has implemented a stricter pay for performance model as a reaction to the implications of the disallowance of expenses from a prior Section 16-111.5B program whose vendor went bankrupt." 2017 Plan at 124; ComEd Cmnts. at 3-4.

ComEd notes that the parties' Comments generally expressed support for the 2017 Plan's proposal to revisit the vendor contracting issue in this docket and obtain much needed clarity. Staff's Response, however, claimed that there is no regulatory uncertainty with respect to vendor contracting. Staff Resp. at 9. ComEd states that it is difficult to understand how Staff has now reached the conclusion that the issue is settled, especially in light of the concerns expressed by the AG, IPA, Ameren, and ComEd, for whom the issue is all but settled. ComEd Rep. at 3-4

ComEd proffers that the present docket thus presents a convenient and timely forum for providing the clarity requested by the parties. Although the parties' views differ regarding the scope of guidance to be provided, ComEd encourages the Commission to provide detailed guidance and, in this vein, also approve the contract templates proposed by ComEd. While some parties have opposed, or expressed hesitation regarding, the approval of ComEd's proposed templates, the disagreement appears to be based solely on concerns about time constraints imposed by the statutory framework rather than any particular issue with the contracts themselves. The IPA, indeed, noted that it has identified no issues with ComEd's proposed contract templates. IPA Resp. at 25. While ComEd appreciates the time constraints imposed by the statute, no party has identified any particular obstacle that presents an insurmountable challenge to reviewing and approving the contracts in this docket. To the contrary, ComEd argues that it is a prudent course of action to pair the approval of the energy efficiency contract templates with the approval of the energy efficiency programs themselves, which involve hundreds of millions of dollars in expenditures. ComEd Rep. at 4.

Regarding the comments in the IPA's Response that it would have "strongly preferred a more pointed identification of what specific concerns necessitated approval of contract templates … and highlighting of key terms within templates" (IPA Resp. at 25), ComEd reiterates that is has been subject to hundreds of thousands of dollars in disallowed costs associated with a vendor that became insolvent, and, as the AG notes, the Commission "never provided specific direction in its Docket No. 14-0567 Order as to what ideal contract terms look like." AG Resp. at 4. It is this disallowance risk and absence of direction regarding specific contract terms that has prompted ComEd's request for approval of its contract templates. With respect to highlighting the operative terms and conditions of the proposed contract templates, ComEd asserts that it included detailed discussion of the key contract terms. ComEd Rep. at 5.

While ComEd believes that general guidance from the Commission will be helpful, general guidance is not sufficient to resolve the contracting uncertainty that remains following the orders in the *2016 Plan Docket* and Docket No. 14-0567. To ensure that utilities, vendors, and stakeholders have the clarity and confidence to move forward with energy efficiency contracts that strike the correct balance, ComEd attached its energy efficiency contract templates to its Comments on the IPA Draft Plan, and requested that they be attached to the filed Plan for Commission review and approval. Because the IPA energy efficiency programs include both ComEd-managed programs and third-party managed programs, ComEd included its contract templates applicable to both kinds of programs. ComEd notes that in its Petition and the filed 2017 Plan, the IPA indicated that it was declining the invitation to include the contract templates, citing to the compressed timeframe of this docket and that these kinds of issues are better suited to the workshop process. IPA Pet. at 7; 2017 Plan at 112.

ComEd points out that the *2016 Plan Docket* already directed interested stakeholders to take up the issue of vendor contracting in the SAG workshop process, and the parties did so during a process that began in January 2016 and concluded in July 2016. And, the 2017 Plan includes the consensus items from that process. Plan at 107-

110. As a result, ComEd opines that the workshop process has been exhausted, and the Commission should approve in this docket the energy efficiency vendor contract templates to be used by the utilities.

ComEd proposes changes to the Plan that elevate and identify the third-party vendor and contracting issues as key policy issues to be decided by the Commission in this docket. To this end, ComEd proposes that the 2017 Plan include additional discussion regarding the procedural history and relevant Commission orders on these issues, as well as descriptions of the utilities' proposed contracting approaches for both utility-managed and third-party managed programs. Specifically, ComEd proposes that the Plan be revised to highlight key terms of its vendor payment provisions in both its pay-for-performance contracts and its contracts for ComEd-managed programs. ComEd Cmnts. at 5.

To assist the Commission in providing additional clarification regarding contract terms and conditions, ComEd recommends that the 2017 Plan also be revised to attach the contract templates that the utilities propose to execute with third-party vendors, whether they are pay-for-performance contracts related to third-party managed programs or contracts related to utility-managed programs. ComEd reasons that this approach will ensure that the Commission can review and approve all relevant contracts, which will provide the clarity and certainty required by the utilities, vendors, and stakeholders. ComEd Cmnts. at 7-8.

5. Staff’s Position

Staff notes that the AG makes two sets of recommendations to the Commission that warrant Commission adoption: 1) a directive to have stakeholders further explore through workshops what constitutes reasonable energy efficiency contract terms that strike the appropriate balance of attracting bidders of all sizes, both local and national, and ensuring that ratepayers or utility shareholders are not left holding the bag for poorly implemented programs; and 2) a directive to the utilities to help clarify to both the utilities and the Section 16-111.5B vendors that the utilities should be negotiating and actively managing the Section 16-111.5B energy efficiency program contracts with the same level of vigor and interest as their Section 8-103 energy efficiency program contracts to ensure ratepayer funds are being used for high quality cost-effective programs that are consistent with best practices and achieve the maximum amount of forecasted savings at the least cost. Staff supports the AG's requests and recommends that the Commission adopt the AG's proposals, which should help improve the quality and success of the Section 16-111.5B energy efficiency programs to the benefit of ratepayers who are paying for these programs. Accordingly, the Commission should adopt the AG's requests. Staff Rep. at 7-8.

Staff notes that ComEd proposes two new sections to the 2017 Plan which are related to ComEd's proposal that the Commission approve in this docket various ComEd vendor contract templates. Staff opines that the Commission should not approve ComEd's proposed contract templates as part of the 2017 Plan for a number of reasons. First, approval of ComEd's proposed contract templates as part of the 2017 Plan would be inconsistent with the PUA, in particular, Section 16-111.5B(a)(5) which provides in part that:

> In the event the Commission approves the procurement of additional energy efficiency, it shall reduce the amount of power to be procured under the procurement plan to reflect the additional energy efficiency and shall direct the utility to undertake the procurement of such energy efficiency, which shall not be subject to the requirements of subsection (e) of Section 16-111.5 of this Act. The utility shall consider input from the Agency and interested stakeholders on the procurement and administration process.

220 ILCS 5/16-111.5B(a)(5). Staff highlights that ComEd did not seek Staff's input on the contract templates. Staff first became aware of ComEd's contract template proposals when ComEd included them with its comments on the IPA's Draft Plan. ComEd apparently failed to seek the IPA's input as well; the IPA makes no reference to reviewing ComEd's contract templates prior to ComEd submitting comments on the IPA's Draft Plan. Finally, in its comments, ComEd makes no mention of seeking interested stakeholders' input on the contract templates. In light of ComEd's apparent failure to seek input from the IPA and interested stakeholders on its contract templates as required by statute, Staff recommends that the Commission not adopt ComEd's contract templates and related proposed modifications to the 2017 Plan. Staff Resp. at 8-9.

Staff recommends that the Commission also decline to adopt ComEd's contract templates and the related proposed modifications to the 2017 Plan for the reasons set forth by the IPA. The IPA correctly asserts that "general guidance from the Commission in combination with and identification and resolution [of] any specific, discrete concerns should achieve the same ends" as attaching contract templates to the IPA Plan. *Id*. Consistent with providing guidance to the utilities, Section 9.3 of the Plan sets forth numerous consensus items related to vendor energy efficiency contracts which are part of the procurement and administration process of energy efficiency procurement which the IPA and other interested stakeholders are to provide input on. 2017 Plan at 109. Staff further agrees with the IPA that, if the Commission is inclined to approve energy efficiency contract templates, such a process - and the templates approved in the process - should apply to all utilities (i.e., Ameren) and not just ComEd. IPA Petition at 7. Finally, Staff agrees with the IPA that litigating contract terms would add additional layers of review and analysis "to an already time constrained proceeding." IPA Petition at 7; Staff Resp. at 9.

Staff submits that despite ComEd's claim to the contrary, there is no regulatory uncertainty regarding vendor contracts. In support of its argument ComEd discusses the Commission's Order in the *2016 Plan Docket* and Docket No. 14-0567. ComEd argues that in the *2016 Plan Docket*, the Commission rejected the withholding of payment for nonperformance, but in Docket No. 14-0567, the Commission disallowed cost recovery for ComEd because ComEd had not withheld payment for nonperformance. Staff Resp. at 9-10. Staff states that the two orders are not inconsistent for the following reasons. First, ComEd fails to acknowledge that the Commission in the 2016 IPA Plan Order clearly stated that, with respect to the ComEd Rider EDA reconciliation proceeding, the "[i]ssues presented in that proceeding will be resolved in that case." *2016 Plan Docket*, Order at 111. Accordingly, any suggestion that the Commission Order in the *2016 Plan Docket* proceeding resolved the contract question raised in Docket No. 14-0567 reconciliation docket is mistaken. Second, ComEd mischaracterizes the *2016 Plan Docket*. The Commission did not reject on the merits Staff's recommendation regarding withholding of payment, but rather simply directed the parties to pursue that issue in workshops. Because the Commission wanted the issues addressed in workshops, it declined at that time to adopt Staff's specific recommendation, but did not speak to the merits of withholding payment. Third, the basic facts in the two dockets are very different. Docket No. 14-0567 deals with assessing the prudence of ComEd management decisions made prior to and during the June 2013 through May 2014 billing period. The 2016 IPA Plan docket concerns a subsequent time period commencing two years later and actions to be taken during that later period of time. Staff claims that any consideration of an order addressing a period of time subsequent to the relevant time of the reconciliation period and issued after the relevant time period, in a prudence analysis, would involve impermissible hindsight review. Staff Resp. at 9-11.

According to Staff, it is also worth noting that ComEd has taken an appeal from the Commission's Order in Docket No. 14-0567 (*ComEd v. Illinois Commerce Comm'n*, No. 1-16-2410, (filed September 13, 2016)). ComEd argued in its application for rehearing that the two orders are "contradictory", (Docket No. 14-0567, ComEd Application for Rehearing at 5), and presumably will raise the same argument on appeal. Staff contends that the issue of whether those two orders are contradictory will be addressed by the Appellate Court in ComEd's appeal and need not be resolved in this proceeding. Staff Resp. at 11.

With respect to ComEd's proposed contract templates, Staff notes that the IPA states that "while ComEd cites workshop process conclusion as grounds for the template approval through this proceeding, these templates were never introduced to the Agency (or presumably any other parties) during the workshop process." IPA Resp. at 25. Putting aside that objection, the IPA states "that it has no (known) objections to the content of the contract templates, but reserves the right to modify its position should other parties identify aspects of the templates that may be problematic." IPA Resp. at 25. Even though the IPA states that it has no known objections to the actual content of the contract templates, Staff has not had sufficient time to address all potential problems with the templates other than to observe that it does have identifiable concerns with the ComEd contract templates. Accordingly, Staff recommends that, in light of ComEd's failure to seek input from the IPA and interested stakeholders on its contract templates as required by statute, the Commission should decline to adopt ComEd's contract templates and related proposed modifications to the 2017 Plan. Staff Rep. at 8-9.

6. IPA's Position

The IPA notes that the AG requests that the Commission require the utilities to treat Section 8-103 and Section 16-111.5B contracts the same in terms of ensuring the best contract terms for ratepayers. While the IPA is supportive of the AG's general objective, the IPA is unclear on what that might constitute. Section 8-103 and Section 16-111.5B feature fundamentally distinct statutory schemes. In the former, a utility designs a portfolio every three years with a defined, limited budget, exercising discretion in determining which programs should be included and at what levels for its proposal to the Commission. Alternatively, under the Section 16-111.5B construct, the utility conducts an RFP for third-parties to bid programs every year, with no defined budgets and no subjective discretion for rejecting otherwise cost-effective bids—a more mechanical exercise designed to "fully capture the potential for all achievable cost-effective savings, to the extent practicable." 220 ILCS 5/16-111.5(a)(5). Expecting one process to mirror the other, the IPA opines, seems unrealistic and unwise given these differences, as the opportunities for shaping program proposals and resulting contracts occur at different points and with entirely different opportunities for leverage held by different parties (primarily the utilities under the Section 8-103 construct and the Commission under Section 16-111.5B). IPA Resp. at 12.

The IPA is also unconvinced that "contract scrutiny" or "ensuring the best contract terms" has been a problem for utility contracts with Section 16-111.5B vendors, at least recently. If anything, disputes over the past year have centered on whether new, more protective contract terms – such as withholding up-front payments, cybersecurity requirements, surety bonds, and other hold-back provisions – have erred too far on the side of protecting against risks of non-performance at the expense of vendor participation. Additional RFP requirements signaling to potential bidders that the utilities will scrutinize and seek to adjust proposed terms based upon utility review of proposals could have a strong chilling effect on vendor participation. Moreover, this new layer of review and scrutiny would empower the utilities with new gatekeeping responsibilities not envisioned by a statutory scheme focused on fully capturing all available cost-effective energy efficiency through an objective analysis of proposals received from the competitive marketplace. The IPA asserts that to the extent that "scrutiny" may manifest itself in "subjectivity" in evaluating a proposal, this appears to be exactly what the statutory scheme is designed to avoid. IPA Resp. at 12-13.

The IPA is additionally concerned that this approach could result in bids misaligned with a vendor's actual capacity or optimal approach. *See* 2017 Plan at 111. These concerns relate to post-bid negotiations; post-Plan approval negotiations (also floated by the AG in Comments) could yield even less benefit, as the bidder would have the backstop of a Commission Order already approving its cost-effective bid. IPA Resp. at 13.

Additionally, the IPA questions the impact of a requirement, which would subject all savings estimates and program design elements to a new layer of utility scrutiny, on the participation of local vendors of limited size already worried about strict contract terms. The IPA appreciates and generally agrees with the concerns identified by the AG, but given that the development and submittal of a proposal alone can constitute a significant allocation of resources for a smaller vendor, introducing further uncertainty about that proposal's fate through a new layer of scrutiny could easily dissuade that entity from participating—badly frustrating the AG's second objection at the expense of its first. IPA Resp. at 13-14.

While the IPA understands the spirit of the AG's request, the IPA believes that the ends sought through the "same treatment" may be best accomplished through maximizing participation in the Section 16-111.5B solicitation process, leading to increased competition and the best possible program designs and terms. *See* 2017 Plan at 112. The IPA believes that the AG's request that the Commission mandate that the "same level of scrutiny" between Section 8-103 and Section 16-111.5B be applied to "ensure that these programs are as cost-effective" should be rejected. IPA Resp. at 14.

According to the IPA, how the AG's proposal would operate in practice is still unclear, but the IPA recognizes that the AG clarified that this suggestion would require the utilities to "scrutinize the implementation strategy and program design, including the energy efficiency measure mix" of each proposal. AG Resp. at 7. To the IPA, one of the primary distinctions between Section 8-103 and Section 16-111.5B is that Section 8-103 requires the utility to build and submit a portfolio of programs presented for Commission approval and Section 16-111.5B allows the market to essentially develop that portfolio through independently developed bids. The IPA asserts that novel program designs, new technologies, and innovative delivery approaches are all possible if a resulting bid is cost-effective with the bidder itself bearing the risk of an ineffective program under a pay-for-performance contract. But unlike a Section 8-103 portfolio, the utility is not the gatekeeper; the objective merits of the bid, as evaluated for cost-effectiveness, serve as the gatekeeper instead. IPA Rep. at 17-18.

The IPA argues that AG's proposal inverts that construct and forces the utility to assume a portfolio development role not envisioned in the law. Perhaps more problematic, any existing assumptions about the right way to design a program would likely have to be imposed onto the bid review process, and innovative new approaches may suffer. The IPA continues that even if the utility would not want to force a bidder to revisit a novel, innovative new program's design, the AG's proposal would force the utility to "scrutinize" those aspects "for consistency with best practices," and the utility would presumably run afoul of this new requirement if it failed to call for the bid's modification. IPA Rep. at 18.

The IPA believes that this mandated funneling of ideas undermines that which is most promising about the Section 16-111.5B paradigm: the ability for new ideas to benefit from an objective review disconnected from established practices. That leveling of the playing field is not only good policy, it is what the law envisions through minimizing any party's role to a passive one in approving cost-effective bids. The IPA contends that the AG's proposal would elevate a flawed idea not envisioned by the law above the most promising elements of Section 16-111.5B that are actually present in the legal construct, and therefore the AG's proposal should be rejected by the Commission. IPA Rep. at 18-19.

The IPA notes that ComEd includes a set of contract templates with its Comments and that those templates were also included with ComEd's comments on the Draft Plan with a request that they be included as an appendix to the IPA's filed 2017 Plan. The IPA explains that, while it understands ComEd's desire for clarity on acceptable terms and conditions, procurement plan approval proceedings are 90-day dockets during which a multitude of issues are considered. Rather than simply attaching a series of forms to a filing, the IPA would have strongly preferred a more pointed identification of what specific concerns necessitated approval of contract templates (especially given that the issue resulting in a prior disallowance for ComEd would seem to have been addressed through withholding up-front payouts to vendors) and highlighting of key terms within templates that ComEd felt could be contentious or problematic. Further, while ComEd cites workshop process conclusion as grounds for contract template approval through this proceeding, the IPA states that these templates were never introduced to the IPA (or presumably any other parties) during the workshop process. IPA Resp. at 24-25.

Nevertheless, the IPA recognizes that these templates have now been introduced in this proceeding, are likely to be commented on by parties, and have been presented by ComEd for Commission approval. That said, the IPA states that it has no known objections to the content of the contract templates, but reserves the right to modify its position should other parties identify aspects of the templates that may be problematic. IPA Resp. at 25.

The IPA also agrees with Ameren that approval of ComEd’s contract templates cannot serve to require Ameren to use contract templates mirroring ComEd’s, and reiterates a concern raised in its petition that, if considered at all, the IPA would prefer that both Ameren and ComEd’s contract templates be considered together. Although not opposing approval of ComEd’s contract templates, the IPA shares Staff’s concerns that these templates would have benefitted from stakeholder review before their submittal with comments on the Draft Plan. IPA Rep. at 19.

According to the IPA, the only apparent regulatory uncertainty necessitating approval of these templates is an issue specific to pre-payment of vendors who later become insolvent, and the IPA understands this to be something now insulated against by disallowing pre-payment. The IPA opines that resolving identified issues is challenging in a 90 day proceeding and forcing parties to detect issues buried in contract templates layers deeper challenges on top of that. IPA Rep. at 19.

7. Commission Analysis and Conclusion

In the *2016 Plan Docket*, the Commission said that the same scrutiny should be applied to third party energy efficiency contracts entered into under Section 8-103 and Section 16-111.5B of the PUA. The Commission provided no further explanation regarding the intent or meaning of this statement. The Commission notes that the AG requests that the Commission require Ameren and ComEd to include in their RFPs notice to vendors that the utilities shall, as a condition of the contracting process, and after Commission approval of a program that passes the TRC and performance risk criteria: 1) scrutinize the cost per kilowatt hour saved to ensure that the price, while passing the TRC, is not inflated and, if necessary, negotiate a reduced cost consistent with the utility’s Section 8-103 contracting practices; and 2) scrutinize the implementation strategy and program design, including the energy efficiency measure mix, to ensure that the program is consistent with best practices. AG Resp. at 6-7. The Commission declines to adopt the AG’s proposal. The Commission finds that the AG’s proposal is inconsistent with the statutory differences between these two types of programs.

The AG’s proposal to require the utilities to scrutinize program design fails to account for the utilities’ different roles in Section 8-103 and Section 16-111.5B energy efficiency programs. The Commission notes that Section 8-103 requires that ComEd and Ameren offer or procure various energy efficiency programs for the purpose of reducing energy consumption. Unlike the utility-designed and implemented energy efficiency plans under Section 8-103, the core of Section 16-111.5B's efficiency procurement is an RFP process where third-party bidders implement those winning programs that are approved by the Commission. In other words, the AG's proposal fails to reflect that Section 16-111.5B envisions a market-driven process.

The Commission agrees with the IPA that the AG's proposal could also make the bid process more subjective, contrary to the statutory scheme. Notably, an extra step of price negotiation could reduce bid participation and increase administrative costs. The Commission finds that increased bid participation is a better method for ensuring that contracts are properly priced, rather than a subjective price negotiation after the RFP. For these reasons, the AG's proposal is not adopted.

The Commission notes that the different contract terms discussed in comments seek to address different issues. Ameren explains that surety bonds are required to ensure that a vendor has the ability to return dollars to customers if actual savings, as determined by the independent evaluator, are less than the savings reported by the implementer. Ameren further explains that holdbacks are designed to encourage implementers to deliver the entire amount of savings as bid. According to Ameren, it sets the surety bond level at 25% of the program cost and its holdback at 5%. This holdback provision means that implementers that fail to achieve 95% of their contractual commitment are subject to losing some or all of the 5% holdback. ComEd explains that its new pay for performance contract eliminates the payment of start-up costs, and that it has also implemented enhanced verification and withholding provisions that limit the amounts ComEd will pay prior to receiving final evaluation results from the independent evaluator. Specifically, ComEd will only pay 90% of verified savings for those measures whose energy savings have been "deemed" by the Illinois Technical Reference Manual. If the measure's energy savings have not been deemed, ComEd will only pay 75% of the verified savings for such measures. The Commission notes that the record does not show whether these specific contract terms are appropriate. That these provisions are designed to protect ratepayers is apparent, but whether they are too protective of ratepayers at the expense of reducing bid participation is not clear.

Moreover, the record lacks evidence to support the adoption of ComEd's proposed contract templates. ComEd did not discuss or explain its reasoning for any specific contract terms. In addition, Staff made clear that these contracts have not been discussed in SAG workshops. Section 16-111.5B states that the "utility shall consider input from the [IPA] and interested stakeholders on the procurement and administration process." 220 ILCS 16-111.5B(a)(5). Based on the record presented and the failure to include interested parties in the development of these contracts, the Commission will not adopt ComEd's contract templates. While the Commission is not opposed to approving contract templates that would be applicable to both utilities, under these circumstances it cannot do so.

The Commission finds that the question of the appropriate level of contract scrutiny, as well as which contract terms best protect ratepayers while not reducing bid participation should be discussed further in SAG workshops. Issues like these are best reviewed in the workshop context, where the stakeholders can consider all of the relevant facts and circumstances in a collaborative environment, rather than in an expedited approval docket.

E. Section 9.5.3 Review of Ameren Illinois TRC Analysis

1. Summary

Section 9.5.3 of the 2017 Plan states that the IPA reviewed the TRC analyses provided by Ameren using the BENCOST tool provided by the utility. The BENCOST model was updated this year to include quantifiable non-energy benefits for water and O&M expenses, a reserve adjustment to the cost of capacity, and an estimate for the future price of carbon. In conducting its review, the IPA examined submitted inputs for accuracy and reasonableness, and performed "stress testing" around program cost-effectiveness parameters (such as adjusting the forward energy price curve, levels of administrative costs, etc.) to develop a better understanding of the impacts of adjustments to the model. The 2017 Plan states that the IPA generally concurred with the Ameren inputs, assumptions, and methodology. 2017 Plan at 114.

The 2017 Plan notes that Ameren included a blanket administrative cost adder of 11.89% for all programs in evaluating individual program cost-effectiveness. This administrative cost adder is lower than the 13.58% proposed by Ameren last year and is nearly the same as the approved 11.5% administrative cost adder from last year's plan approval (a percentage adder which reflected the removal of non-scalable costs for the Potential Study consistent with the Commission's directive in the *2016 Plan Docket*). *See 2016 Plan Docket*, Order at 97-98; 2017 Plan at 115.

According to its submittal, Ameren's 11.89% administrative cost adder is composed of 3.97% for Evaluation, Measurement and Verification ("EM&V") (compared to 3.5% last year). The 2017 Plan notes that several commenters on the Draft Plan raised concerns that this amount exceeded the 3% cap on "[t]he resources dedicated to evaluation" in 220 ILCS 5/8-103(f)(7) and consensus items regarding administrative cost adders. Against the backdrop of the Commission's Order in the *2015 Plan Docket*, however, the IPA's primary concern is whether the adder reflects actual costs. The IPA states that it has no reason to believe that this does not reflect actual administrative costs, and thus is comfortable with using a 3.97% value. The administrative adder also include 5.61% for administration (compared to 5% last year), and 2.3% for marketing, education and outreach (compared to 3% last year). In the *2015 Plan Docket*, the Commission required that the utilities "track administrative costs by program in order to aid in future determinations of appropriate administrative cost assumptions to use in the TRC analysis of the Section 16-111.5B programs." *2015 Plan Docket*, Order at 224. The 2017 Plan states that Ameren provided follow-up information demonstrating costs incurred by program to substantiate actual administrative costs. The 2017 Plan opines that these administrative cost levels appear to be within an expected range based on prior years, and that small changes to the administrative adder which could come from minor adjustments would not appear to impact which programs pass or fail the TRC. 2017 Plan at 115.

As with last year, the 2017 Plan observes that fewer proposed programs passed the Ameren TRC screening than the ComEd screening. While this could be a function of the bids themselves or the TRC methodology applied, it appears that lower energy and capacity prices in the Ameren service territory may also simply make the test more difficult to pass. Of the 11 programs that did not pass the TRC, values ranged from 0.15251 to 0.98.252. 2017 Plan at 115.

In addition to calculating TRC values for each program, Ameren also provided Utility Cost Test ("UCT") results for each program (as required by Section 16-111.5B(a)(3)(D) of the PUA) and an assessment of the cost of procuring each individual energy efficiency program as compared to its calculation of the Cost of Supply ("COS") (provided pursuant to Section 16-111.5B(a)(3)(E)). The calculation methodology and application of the COS was a subject of significant debate in the consideration of the 2016 Plan, with the IPA believing that Ameren's approach to calculating the COS—an approach which disregarded gas savings and transmission & distribution savings, which differed from Ameren's established practice from prior years, and which differed from (and continues to differ from) the ongoing practice of ComEd—was inappropriately restrictive, especially when used to advocate for the non-adoption of otherwise cost-effective energy efficiency programs. 2017 Plan at 115-16.

The IPA continues to have reservations about the methodology used by Ameren to calculate the COS, and one program which passed the TRC test failed the Ameren COS test. As the IPA is directed by law to include "energy efficiency programs and measures it determines are cost-effective," and because "cost-effective" refers to a program passing the TRC test (which, by law, requires taking into account gas savings, as is done through the TRC but not through the Ameren approach to calculating "cost of supply"), the 2017 Plan states that this program is included. However, the IPA is mindful of the Commission's acceptance of the Ameren approach to calculating the COS in the *2016 Plan Docket* and the discretion the Commission exercised in deciding not to include two programs with positive TRC test results which failed Ameren's COS analysis, and understands that the Commission could again use its discretion to disqualify that program. 2017 Plan at 116.

2. AG's Position

The AG notes that Ameren's 3.97% EM&V adder exceeds the statutory cap for EM&V of 3 percent, as provided in Section 8-103(f)(7) of the PUA. It is unclear to the AG why evaluation of IPA programs would exceed this cap, which the General Assembly deemed reasonable in its consideration of Section 8-103 programs. The AG argues that program costs are increased when unexplained administrative costs are added to the cost per kilowatt hour saved. AG Cmnts. at 9.

The AG submits that the 2016 SAG Report lists consensus items from the IPA Workshop process. One of those provisions states, "Expenditures on evaluation should be capped for the Section 16-111.5B Programs as they are for the Section 8-103 Programs. Each Program's evaluation budget should not be restricted to three percent (3%) of the Program budget, but evaluation costs should be limited to three percent (3%) of the combined Section 16-111.5B Programs' budget." 2016 SAG Report at 22. The AG asserts that the Commission should order the IPA and Ameren to revise the program costs submitted in the Ameren bid to remove any evaluation costs above 3% from the costs assessed to the programs. AG Rep. at 7.

With respect to Ameren's COS test, it is the AG's understanding that Ameren's methodology may exclude avoided transmission and distribution costs. Such a position is contradicted by the General Assembly's specific finding that "[r]equiring investment in cost-effective energy efficiency and demand-response measures will reduce direct and indirect costs to consumers by decreasing environmental impacts and by avoiding or delaying the need for new generation, transmission, and distribution infrastructure." 220 ILCS 5/8-103(a). Unless it can be shown that Ameren is accounting for these avoided costs in some other aspect of the TRC calculation, the AG argues that the Commission should include a finding that those costs be reflected by the utilities. AG Cmnts. at 10.

The AG states as well that, in examining the cost-effectiveness of programs designed for residential customers, and in particular, low income customers, avoided costs should include assumptions about reduced billing and collection costs. In general, it is unclear what Ameren's assumptions were regarding avoided costs in its TRC calculation. It is the AG's understanding that the Ameren cost-effectiveness tool and related assumptions are not public. It is unclear to the AG why these inputs are kept confidential. Absent a compelling explanation from a utility, the AG urges the Commission to require Ameren to make these costs public. AG Cmnts. at 10.

3. Ameren's Position

The AG argues that Ameren's 3.97% adder exceeds the statutory cap for EM&V of 3 percent, but Ameren avers that there is no statutory cap for EM&V. The AG cites to Section 8-103(f)(7) as support, but Ameren points out that this is an IPA procurement plan docket, and Section 8-103(f)(7) does not control. There is no such cap in Section 16-111.5B. The AG offers no legal argument beyond the unsupported assertion that a "cap . . . which the General Assembly deemed reasonable in its consideration of Section 8-103 programs" must also apply to Section 16-111.5B, because "[i]t is unclear why" the situations would be treated differently. Ameren opines that what matters is that the input used by Ameren matches up with tracked costs, and it does. Ameren recommends that the AG's position not be adopted. Ameren Resp. at 11.

Turning to the AG's contentions regarding why Ameren's avoided costs are confidential, Ameren states that its avoided costs are based on competitive and sensitive information, like Ameren's pricing curves. The Commission has found such information falls within the kind that should be protected. *See, e.g.*, *MidAmerican Energy Co.*, Docket No. 98-0116, Interim Order at 2-3 (May 6, 1998) (declaring confidential and proprietary information relating to (i) a public utility's prices of sales for resale, (ii) a public utility's prices for purchases for resale, and (iii) a public utility's power production costs). The AG's request should be rejected for that reason alone. In addition, Ameren notes that one of the primary drivers of a program's acceptance into the 2017 Plan is its attainment of a TRC value greater than 1.0. If all of the utility-side inputs are known to the bidders in detail, then these for-profit marketplace participants will be free to craft their non-duplicative, non-competing bids in such a way as to pass the TRC test with a value as close to 1.0 as possible, thereby increasing the "costs" they recoup from Illinois ratepayers, and therefore their own profits, at the expense of lost benefits. Ameren contends that the Commission should disregard the AG's arguments regarding the purported "transparency" issue that has been raised. Ameren Resp. at 14-15.

NRDC has joined the AG's argument that Ameren's TRC inputs should be made public. *See* NRDC Resp. at 7. Ameren asserts that NRDC tacitly recognizes this position is in contradiction of the non-disclosure agreement they both executed in order to gain access to Ameren's avoided cost data. The utilities and the IPA have access to the necessary data, and that data is confidential, which is why NRDC had to sign a non-disclosure agreement to access it. Ameren Rep. at 11-12.

Finally, Ameren suggests that it is not NRDC's job to second-guess the TRC analysis for the IPA procurement process, nor is there any legal basis for NRDC's demand that it should have the opportunity to do so. The PUA assigns the task of calculating cost-effectiveness first to the utilities, see 220 ILCS 5/16-111.5B(a)(3)(C), and ultimately to the IPA, *see* 220 ILCS 5/16-111.5B(a)(4). NRDC does not take any issue with the IPA's TRC analysis—the final analysis that was actually used when determining which programs to include in the Plan. Ameren argues that the Commission should disregard NRDC's argument, and Ameren's avoided costs should remain confidential. Ameren Rep. at 12.

4. ComEd's Position

As part of its review of Ameren's TRC test analysis, the AG proposes that Ameren be required to make its cost-effectiveness tool and related assumptions public. While ComEd takes no position on the substance of this issue as it relates to Ameren, ComEd cautions that this issue is utility-specific, and ComEd's software licensing agreement for its cost-effectiveness tool – DSMore – prohibits ComEd from making the tool publicly available. ComEd Resp. at 6-7.

5. NRDC's Position

NRDC shares the AG's concerns that the avoided costs and the tool used by Ameren to assess the cost-effectiveness of proposed efficiency programs are treated as confidential and not public. While the IPA had the opportunity review Ameren's avoided costs and pass its judgement as to their reasonableness, other parties did not. It is certainly plausible that other parties may find areas of concern that the IPA did not find. Indeed, after signing a non-disclosure agreement, NRDC had the opportunity to review and discuss with Ameren an earlier version of its avoided costs assumptions. NRDC expressed several concerns about them to Ameren. While responses from Ameren suggest that some of its concerns were probably adequately addressed, it appears that others were not, though NRDC cannot definitively confirm whether that was the case because Ameren did not provide the final avoided costs it used to screen IPA program proposals. NRDC Resp. at 7.

NRDC also contends that the short time periods available for commenting on the IPA's plan do not allow for adequate investigation of the reasonableness of the utilities' final cost-effectiveness analyses if avoided cost assumptions and cost-effectiveness analyses are considered confidential. NRDC opines there is not enough time to issue discovery and receive responses, let alone to analyze an issue as complex as avoided costs or cost-effectiveness screening. Thus, if Ameren or any other utility is going to contend that its avoided costs or its cost-effectiveness analyses are confidential, there needs to be a modification to the current process to enable third-party review. NRDC suggests that one option might be to require utilities to make available avoided cost and screening tools (to parties signing non-disclosure agreements if necessary) at the time that the IPA's draft plan is submitted in mid-August. NRDC Resp. at 7.

NRDC notes that the AG requests that the Commission direct Ameren to remove 0.97% from their EM&V adder in the TRC to reset that adder to the 3% level required for Section 8-103 programs. The IPA disagrees that this adjustment would be warranted. Unlike the 3% budget allocation value used in Section 8-103, to calculate the TRC, Ameren used the previous program year's EM&V budget (set at 3%) and applied it to actual spending (which, because lower than forecast, translated into a higher net percentage) to develop an EM&V adder. NRDC opines that this approach seems most consistent with the Commission's requirement that administrative cost adders be based on actual administrative costs. *See 2015 Plan Docket*, Order at 224-225; IPA Resp. at 22-23.

6. Commission Analysis and Conclusion

In the *2015 Plan Docket*, the Commission stated the following regarding administrative costs:

> NRDC also argues that Ameren is overstating its overhead or administrative costs as used in the TRC test and notes that ComEd does not use a similar percentage adder when performing the TRC test. Ameren disagrees, while Staff suggests Ameren should not be using any generic adder for all programs as administrative costs are likely to vary by program size type and size. The Commission finds the quality of evidence relating to this issue lacking. No party presented evidence regarding Ameren specific overhead or administrative costs though it is almost certain they exist. To the extent the utilities do not explicitly track this information already, the Commission hereby directs Ameren and ComEd to track administrative costs by program in order to aid in future determinations of appropriate administrative cost assumptions to use in the TRC analysis of the Section 16-111.5B programs.

2015 Plan Docket, Order at 224. The 2017 Plan states that Ameren included a blanket administrative cost adder of 11.89% for all programs in evaluating individual program cost-effectiveness. This 11.89% includes 3.97% for EM&V. The IPA apparently accepts that the 3.97% is consistent with Ameren's actual costs. If true, then the 3.97% is consistent with the Commission's general directive in the *2015 Plan Docket*. The Commission, however, also sent this issue to SAG and it appears that consensus has been reached regarding a cap on EM&V costs. The 2016 SAG Report states that:

> Expenditures on evaluation should be capped for the Section 16-111.5B Programs as they are for the Section 8-103 Programs. Each Program's evaluation budget should not be restricted to three percent (3%) of the Program budget, but evaluation costs should be limited to three percent (3%) of the combined Section 16-111.5B Programs' budget.

2016 SAG Report at 22. Based on the record presented it is not clear if Ameren's administrative adder reflects 3.97% for each individual program or 3.97% of the combined

Section 16-111.B programs' budget. Without some explanation of why Ameren's EM&V administrative adder is above the 3% agreed to in the SAG, the Commission must adopt the AG's proposal.

It is clear that the utilities' inputs to the TRC test analysis should remain confidential. It is important that bidders not have access to this information. The Commission agrees with NRDC that the plan review process could be improved by making the avoided cost and screening tools available earlier. Thus, NRDC's proposal to provide access during the review of the Draft Plan is adopted, with the understanding that the non-disclosure agreements will need to be signed.

F. Section 9.5.4 Programs Deemed "Not Responsive to the RFP" by Ameren Illinois and Section 9.5.4.1 Policy Implications

1. Summary

Section 9.4.2 of the 2017 Plan, discussed above, explains that the extent to which programs can include gas savings has been an issue for some of Ameren's bids. Ameren has included a provision in its RFP that attempts to limit measures that have gas savings. The 2017 Plan states that Ameren has used that provision to recommend rejection of certain programs or to evaluate others with none or only some of their gas savings. The IPA does not agree with this approach, arguing it is inconsistent with the law. The IPA believes that programs (as opposed to specific measures within the program) should be evaluated in their entirety using both the gas and electric savings, consistent with practice in each year prior to this year, the same as ComEd used in its submission, and in the view of the IPA, as intended by the plain language of the law. 2017 Plan at 112-113.

Section 9.5.4 of the 2017 Plan states that Ameren determined that two proposals were not responsive to its RFP. According to the 2017 Plan, Ameren referenced the following statement within is RFP:

> The purpose of this RFP is to procure energy efficiency programs that acquire electric savings in accordance with Section 5/16-111.5B of the Act. Accordingly, any programs or measures designed to acquire gas savings will not be accepted. However, if an electric program design captures incidental gas savings through multi-fuel measures, it may be considered. Such savings will be considered for purposes of the TRC test.

Ameren contends two of the proposals did not meet this requirement because the focus on gas savings is too great, and therefore Ameren did not fully evaluate these two proposals. 2017 Plan at 116.

Section 9.5.4.1 of the 2017 Plan states that the IPA understands Ameren's concern that the IPA procurement plan process could include the approval of energy efficiency programs that might otherwise be funded by gas ratepayers (for instance, pursuant to Section 8-104 of the PUA) rather than a potentially distinct universe of electric ratepayers taking electric distribution service from Ameren. Conceptually, IPA procurement plans—and the IPA itself—generally address only electricity load requirements and not gas supply. However, the IPA is concerned that a disqualifying approach in the treatment of programs featuring considerable gas savings may be inconsistent with the PUA and the IPA Act. The 2017 Plan notes that Section 16-111.5B(b) of the PUA requires that "the term 'cost-effective' shall have the meaning set forth in subsection (a) of Section 8-103" (i.e., "means that the measures satisfy the total resource cost test"), which in turn requires that "avoided natural gas utility costs" be included in a cost-effectiveness calculation. While the IPA appreciates that adopting such programs could result in cross-subsidization of gas ratepayers by electric ratepayers, the intent of the General Assembly in enacting Section 16-111.5B, as taken from the language of the statute itself, appears to be that gas savings are not ineligible for consideration under Section 16-111.5B and in fact that such savings must be taken into account in assessing the cost-effectiveness of proposed programs. Further, using dollar savings (rather than British thermal units ("BTU"), as Ameren employed) to compare the gas and electric impacts of programs demonstrates that due to the low price of gas compared to electricity, these programs actually generate more financial savings on the electric side. The 2017 Plan states that because the concept of cost-effectiveness ultimately reduces impacts to their financial terms, the assertion that these programs have more gas savings than electric savings is arguably incorrect and not a justification for their exclusion. 2017 Plan at 116-117.

2. Ameren's Position

Ameren states that it has always calculated the cost-effectiveness test in compliance with the law (and considering both electric and gas benefits), but Ameren maintains that programs which produce primarily gas savings should not be a part of the Section 16-111.5B electricity procurement plan approved by the Commission. Ameren Cmnts. at 9.

Ameren notes that pursuant to Section 16-111.5B(a)(4), the IPA "shall include in the procurement plan prepared pursuant to paragraph (2) of subsection (d) of Section 16-111.5 of this Act energy efficiency programs and measures it determines are cost-effective." 220 ILCS 5/16-111.5B(a)(4). And, as noted by the IPA, a program is "cost-effective" if it passes the TRC test, a measure which includes gas savings. Thus, the IPA should include in its proposed procurement plan all cost-effective programs and measures, even those programs and measures which are rendered cost-effective in part by the gas savings they produce. Ameren asserts that there is no debate in this proceeding regarding how the TRC value should be calculated, or whether Ameren calculated it in the manner required by statute. Ameren Cmnts. at 9-10.

According to Ameren, unlike the IPA, the Commission considers more than just cost-effectiveness when it ultimately decides whether to approve or reject the programs submitted to the Commission for review. The Commission approves cost-effective programs and measures for inclusion in the IPA Plan "to the extent practicable" (*see* 220 ILCS 5/16-111.5B(a)(5)), and the Commission has previously held that the quoted language "gives [the] Commission the authority to set practical limits on the procurement of [energy efficiency]" (*2016 Plan Docket*, Order at 100). "If the General Assembly had intended to require all [energy efficiency programs or measures] that passed the TRC Test to be included in an IPA Plan, it would not have used any qualifier at all." *2016 Plan Docket*, Order at 100-101. "The phrase 'to the extent practicable' is a qualifying phrase that allows th[e] Commission to exercise judgment and flexibility." *2016 Plan Docket*, Order at 101; Ameren Cmnts. at 10.

Ameren argues that the utilities are therefore mandated by the PUA to provide the Commission with additional information that aids the Commission in its exercise of judgment and flexibility. Among other things, as a part of their assessments, the utilities are required to prepare: 1) an "[a]nalysis of how the cost of procuring additional cost-effective energy efficiency measures compares over the life of the measures to the prevailing cost of comparable supply" (*see* 220 ILCS 5/16-111.5B(a)(3)(E)); and 2) "[f]or each expanded or new program, the estimated amount that the program may reduce the agency's need to procure supply" (*see* 220 ILCS 5/16-111.5B(a)(3)(G)). Ameren asserts that it is easy to see how a program that produces primarily gas savings can run afoul of these cost-of-electricity-focused guideposts, regardless of whether a program passes the TRC test. For example, a combined gas-and-electric energy efficiency program that serves both electric-only and dual-fuel customers in Ameren's service territory might pass the TRC test in part because of the gas savings it produces for the dual-fuel customers. But the same program may not look like a good deal for Ameren's electric-only ratepayers when those gas savings are stripped out pursuant to the COS analysis (see 220 ILCS 5/16-111.5B(a)(3)(E)). Ameren Cmnts. at 10-11.

Moreover, the costs of the programs procured by an IPA procurement plan are borne exclusively by electric ratepayers and are passed through Ameren's Rider EDR. *See* 220 ILCS 5/16- 111.5B(a)(6). Ameren explains that if an electric-only ratepayer is paying more than $1 for each $1 reduction in the cost of his or her electric service that results from a combined gas-and-electric energy efficiency program, that means the customer is subsidizing the gas savings accruing to the benefit of other, dual-fuel, customers. This would run afoul of a cardinal principle of the PUA, which is that the State's regulation of public utilities shall ensure "[e]quity," meaning "the fair treatment of consumers and investors in order that . . . the cost of supplying public utility services is allocated to those who cause the costs to be incurred." 220 ILCS 5/1-102(d)(iii); Ameren Cmnts. at 11.

Ameren suggests that the IPA appears unwilling to acknowledge the distinction between its role and the role of the Commission, and the fact that the Commission can consider more than just baseline cost-effectiveness when deciding whether to include the programs and measures submitted by the IPA in the final procurement plan. For example, there can be no reasonable dispute that the Commission should consider the longstanding principle of cost causation, embodied in the language of the PUA, *see* 220 ILCS 5/1-102(d)(iii), when it makes the ultimate decision about whether to approve a program for inclusion in the 2017 Plan. Ameren Cmnts. at 13.

Ameren explains that the UCT, the COS analyses, and the electric-only TRC test, which Ameren ran during the course of its bid analysis, are not replacements for the TRC test. They are additional considerations provided to assist the Commission in exercising its discretion when deciding whether to approve particular Section 16-111.5B programs or measures, and they are firmly grounded in the plain language of the PUA. *See* 220 ILCS 5/16-111.5B(D), (E); 220 ILCS 5/1-102(d)(iii) (stating the principal of "[e]quity," meaning "the fair treatment of consumers and investors in order that . . . the cost of supplying public utility services is allocated to those who cause the costs to be incurred."). Ameren maintains that when those measures suggest that a program requires the cross-subsidization of gas savings by electric-only ratepayers, it is within the Commission's discretion to exclude the program on that basis. Ameren Resp. at 16.

The IPA disagrees with the foregoing Commission precedent defining the qualifying term "to the extent practicable" to allow the Commission to exercise "judgment and flexibility." IPA Resp. at 15-16. Ameren notes that this exact issue has already been litigated between these same parties and has already been decided. While the Commission is not strictly bound by the principles of res judicata and collateral estoppel, before it departs from its own precedent, "[i]t is incumbent upon the Commission to explain and give reasons for its departure from an established past practice, i.e., why it is treating a like situation differently." *See City of Naperville*, Docket No. 03-0779, Order (September 9, 2004), 2004 Ill. PUC LEXIS 513, *38 (citing *Abbott Laboratories v. Ill. Commerce Comm'n*, 682 N.E.2d 340 (1st Dist. 1997) (stating that where the Commission departs from its usual rules of decision to reach a different, unexplained result in a single case, it deprives a party of equal treatment); *Citizens Utility Board v. Ill. Commerce Comm'n*, 683 N.E.2d 938 (1st Dist. 1997) (observing that Commission decisions are entitled to less deference where it departs from past practice and further noting that the Commission is required to provide findings and analysis sufficient to allow for informed judicial review)). Ameren submits that by offering only the exact same argument it provided to the Commission last year, the IPA has not given the Commission a worthy reason to depart from its prior final decision. Ameren Rep. at 14.

With respect to the COS issue, Ameren points out that supply, transmission, and distribution are three different components of the electric service Ameren provides to customers, and the associated costs are likewise three different components of the cost of the electric service Ameren provides to customers. The PUA states that a utility must provide the IPA (and the Commission) with an "analysis of how the cost of procuring additional cost-effective energy efficiency measures compares over the life of the measures to the prevailing cost of comparable supply." 220 ILCS 5/16-111.5B(a)(3)(E). Elsewhere, it makes clear that the transmission and distribution should be considered, as well. For example, it also requires the utilities to provide the IPA (and the Commission) with an "[a]nalysis showing that the new or expanded cost-effective energy efficiency programs or measures would lead to a reduction in the overall cost of electric service." 220 ILCS 5/16-111.5B(a)(3)(D). Ameren states that the TRC test, as every stakeholder agrees, includes all of the above. Ameren Resp. at 12.

Ameren argues that when one subpart of a particular statute references the "overall cost of electric service" - an amount that clearly includes the costs of supply, transmission and distribution - and the very next subpart references the "cost of comparable supply," they cannot mean the same thing. *See Blum v. Koster*, 235 Ill. 2d 21, 29 (2009) (explaining that a statute must be construed in a manner to avoid rendering any part of it meaningless or superfluous). Instead, Ameren avers that the plain meaning of the term "cost of comparable supply" means what it says, and not the cost of comparable supply plus transmission plus distribution, as Ameren understands the AG to advocate. Moreover, Ameren notes that the Commission already used Ameren's COS analysis as a basis for the exclusion of cost-effective programs in last year's IPA Plan docket. *See 2016 Plan Docket*, Order at 100-103 (e.g., "The only reduction in the cost of electric service that would take place with energy efficiency programs that are more expensive than electricity would be to shift the cost of electricity onto the purchase of energy efficiency, at a greater price. Procurement of such energy efficiency programs seems to contravene the spirit, if not the letter, of this portion of the statute."); Ameren Resp. at 12-13.

Ameren reasons that faced with that precedent, the AG's only legal reference in support of its position is to Section 8-103(a), which states that "[r]equiring investment in cost-effective energy efficiency and demand-response measures will reduce direct and indirect costs to consumers by decreasing environmental impacts and by avoiding or delaying the need for new generation, transmission, and distribution infrastructure." 220 ILCS 5/8-103(a). Ameren notes that the AG is citing to Section 8-103 for authority in a Section 16-111.5B docket, without any showing of why the statements contained therein should apply. Ameren contends that the AG's arguments should not be considered. *People v. Butler*, 354 Ill. App. 3d 57, 68, 819 N.E.2d 1133, 1142 (Ill. App. Ct. 1st Dist. 2004) ("this argument is undeveloped and the defendant failed to cite any supporting authority. As a consequence, the argument is waived."). Ameren Resp. at 13. In addition, Ameren argues that the reference to "avoided transmission and distribution infrastructure," in the language quoted by the AG, is clearly tied to the earlier reference to "cost-effective energy efficiency and demand-response measures." 220 ILCS 5/8-103(a). "Cost-effective" means that the programs pass the TRC test and avoided transmission and distribution costs are included in the TRC calculation. Ameren adds that issue is not in dispute and proves nothing when addressing the COS issue. Ameren Resp. at 13.

Ameren continues that even if the introductory language from Section 8-103(a) were to apply to Section 16-111.5B, it could not in any way convert the meaning of Section 16-111.5B(a)(3)(E) to anything other than what its plain language says. That is because the specific controls the general, *see Weber v. Winnebago County Officers Electoral Bd*., 966 N.E.2d 462, 469, 2012 Ill. App. LEXIS 123, *18, 2012 IL App (2d) 120051, 23 (Ill. App. Ct. 2d Dist. 2012), and because the more recently enacted of two conflicting statutes will prevail. *See County of Macon v. Edgcomb*, 654 N.E.2d 598, 602 (Ill. 1995). In other words, even if something in the header paragraph of Section 8-103 could be read to conflict with Section 16-111.5B's specific, explicit directive to provide a comparison to the cost of supply, it would make no difference, because the newer, narrower directive controls. Ameren Resp. at 14.

Moreover, Ameren claims that the reason for the PUA's inclusion of this additional comparison is plain from the face of the statutory language. The IPA's function is to procure supply. *See generally* 220 ILCS 5/16-111.5. The IPA does not procure transmission or distribution. The General Assembly was obviously concerned with measuring the impact that the procurement of incremental energy efficiency has on the IPA's capacity procurement, both quantitatively and financially. That is why, for example, Section 16-111.5B(a)(3)(G) requires, "[f]or each expanded or new program, the estimated amount that the program may reduce the agency's need to procure supply." 220 ILCS 5/16-111.5B(a)(3)(G). This is also why the PUA requires a comparison to the "cost of [the] comparable supply" which the IPA will no longer need to procure. 220 ILCS 5/16-111.5B(a)(3)(E). In Ameren's opinion, that information should matter a great deal to the IPA, if it is handling its procurement duties responsibly. To be clear, the "prevailing cost of comparable supply" used by Ameren, when evaluating the bids, included only the energy and capacity components of the TRC equation. In short, there is nothing odd or exceptional about the inclusion of the COS measure among those which the utilities are required to provide to the IPA and to the Commission. Ameren Rep. at 17.

Ameren notes that NRDC, like the AG, wrote to address the gas savings issue. NRDC has taken the position that, to the extent a non-TRC test is used to measure cross-subsidization, it should be the UCT, rather than an electric-only TRC test. Ameren agrees with NRDC that an electric-only TRC compares all costs, including both the program costs and the portion of measure costs that are borne by program participants, to electric benefits alone. But NRDC goes on to state that "[s]uch a test does not make sense as a means of assessing whether cross-subsidization of gas customers by electric customers is a concern." NRDC Cmnts. at 2. In part, NRDC criticizes the electric-only TRC because other non-electric benefits that accrue to program participants are not considered. Ameren responds that this is why an electric-only TRC test is valuable to discern the existence of cross-subsidization. It compares all of the program costs (all of which, in the context of Section 16-111.5B, are borne by electric ratepayers) to the electric benefits (which are the benefits electric ratepayers get in exchange for bearing all of the costs). In this way, Ameren explains, the Commission can see whether a program is cost-effective under the TRC test only because electric ratepayers are paying for benefits that accrue to gas customers, and not to them. Ameren Resp. at 16-17.

That said, Ameren agrees that the UCT is a useful metric in this context. Ameren does not believe it is an either-or question, and that both the UCT and the electric-only TRC analysis can be useful to the Commission in ferreting out cross-subsidization. The Commission does not have to choose one over the other. Ameren Resp. at 17.

Ameren, however, agrees with the broader consensus among the parties to this docket that it should use an electric-only UCT test to screen for cross-subsidization because of the inclusion of program participant costs in the electric-only TRC. *See, e.g.*, AG Resp. at 10 (advocating for an electric-only UCT "because the UCT only recognizes benefits that accrue directly to the electric system, and thus electric ratepayers" and "[s]o long [as] the UCT benefit-cost ratio exceeds 1.0, all electric ratepayers are better off, regardless of the presence of additional gas benefits"). Accordingly, Ameren will use an electric-only UCT to screen for cross-subsidization in the future, per the request of Staff, the AG, and NRDC, when compiling its assessment. Ameren still advocates for the Commission to use its discretion to not approve programs that do not pass that screen. Ameren Rep. at 18-19.

3. AG's Position

The AG agrees with the IPA's legal analysis on this point, and supports the IPA's objection to Ameren's exclusion of a program because it includes natural gas savings. As the IPA notes, "cost-effective" means that the measures satisfy the total resource cost test, which requires that the TRC analysis count, as a benefit, "other quantifiable societal benefits, including avoided natural gas utility costs." 220 ILCS 5/8-103(a); 20 ILCS 3855/1-10; 2017 Plan at 116; AG Cmnts. at 11.

The AG argues that Section 16-111.5B requires Ameren to solicit third parties for energy efficiency resources and to forward those bids that pass the TRC test to the IPA for approval. Based solely on this criterion, all the hypothetical program designs posited by Ameren should be forwarded to the IPA because they all pass the TRC, which Ameren did. However, 220 ILCS 5/16-111.5B(a)(3)(D) and (E) also require the utility to submit to the IPA "an analysis showing that the new or expanded cost-effective energy efficiency programs or measures would lead to a reduction in the overall cost of electric service" (Section 16-111.5B(a)(3)(D)) and an "analysis of how the cost of procuring additional cost-effective energy efficiency measures compares over the life of the measures to the prevailing cost of comparable supply" (Section 16-111.5B(a)(3)(E)). The AG notes that use of the word "compare" stands in contrast with the analysis called for in Section 16-111.5B, which states that the utilities provide an "[a]nalysis showing that the new or expanded cost-effective energy efficiency programs or measures would lead to a reduction in the overall cost of electric service." 220 ILCS 5/16-111.5B(a)(3)(D). The cost of electric service must reasonably be viewed to include all costs associated with getting electricity to the customer's meter. The AG submits that this is effectively what is defined by the UCT. The UCT is similar to the TRC test except that it only counts the societal benefits associated with the electric utility system and ignores all other benefits. AG Resp. at 8-9.

The AG adds that the calculation methodology and application of the COS was a subject of significant debate in the consideration of the 2016 Plan. The AG opines that a COS analysis that fails to incorporate recognition of avoided transmission and distribution costs, as well as avoided line losses from efficiency resources, is inconsistent with what is known to be true: that the cost of avoided supply also includes the transmission and distribution costs that are necessary to deliver the supply. AG Resp. at 9.

The AG is not advocating for the cross-subsidization of electric energy efficiency programs by gas customers, as Ameren suggests would occur. The AG avers that if a program passes the TRC and the UCT, including a recognition of transmission and distribution avoided costs and avoided line losses, the program is eligible for inclusion in the portfolio. This is because the UCT only recognizes benefits that accrue directly to the electric system, and thus electric ratepayers. The AG argues that if the UCT benefit-cost ratio exceeds 1.0, all electric ratepayers are better off, regardless of the presence of additional gas benefits. Further, even if a hypothetical program did not pass the UCT but did pass the TRC, Ameren can and should explore options that can result in a positive UCT prior to any program rejection. For example, Ameren could ask the bidder if they were willing to more heavily – or even solely – target customers with electric-only end uses. Similarly, without suggesting that any sort of adjustment to its 8-103 portfolio should occur in the instant case, Ameren, as the gas utility in the territory running Section 8-104 programs, could consider in the future contributing gas efficiency funds to the overall cost-effective program to ensure that all electric ratepayers would benefit and that the portion of the program funded through Section 16-111.5B would pass the UCT. These analyses are in keeping with the mandate in Section 16-111.5B to "fully capture(s) the potential for all achievable cost-effective savings, to the extent practicable". 220 ILCS 5/16-111.5B(a)(5). AG Resp. at 10.

In response to the AG's Comments, Ameren argues that the Commission has the authority to exclude programs that pass the TRC for other reasons, including the "cross-subsidization of gas savings by electric-only ratepayers". Ameren Resp. at 16-17. The

AG does not dispute the fact that the Commission may exclude programs that otherwise pass the TRC, "if the Commission determines they fully capture the potential for all achievable cost-effective savings, to the extent practicable, and otherwise satisfy the requirements of Section 8-103" of the PUA. 220 ILCS 5/16-111.5B(a)(5). However, Ameren argues that the Commission should make this exclusion finding on the basis of its contention that programs that result in gas savings necessarily result in a cross subsidy from electric to gas ratepayers. That position is inconsistent with Section 16-111.5B. AG Rep. at 7.

As the AG, NRDC and Staff Responses have shown, so long as a program passes the UCT, the electric ratepayers will receive greater electric system benefits than costs incurred. This is precisely what the UCT does: it compares the electric system benefits to the cost to electric ratepayers. The AG maintains that any programs passing the UCT should be accepted, as any additional gas benefits are simply an added societal benefit that in no way hurts the electric ratepayers. AG Rep. at 8.

4. Staff's Position

Staff shares Ameren's concern regarding programs that are not primarily focused on electric savings. The IPA should procure measures that are predominately justified based upon how the measures save electricity, reduce the overall costs of electric service, and compare to the prevailing cost of comparable supply. These are considerations specifically identified in Section 16-111.5B. The IPA is correct that natural gas savings "must be taken into account in assessing the cost-effectiveness of proposed programs." 2017 Plan at 116-117. Staff, however, agrees with the approach specified in Ameren's RFP that incidental gas savings should be considered when an electric program design captures incidental gas savings through multi-fuel measures. 2017 Plan at 116; Staff Cmnts. at 14.

Staff commends the IPA for seeking and Ameren for producing additional information with respect to the two programs that Ameren identifies as overly reliant on gas savings. This additional information regarding the net electric benefits of these programs provides additional context with respect to the role of gas savings for these programs. This information, as well as other available and relevant information, should inform the Commission's decision as to whether these two programs should be approved and included within the IPA's Procurement Plan. Staff Cmnts. at 14.

Staff supports NRDC's objection recommending a secondary test to address the issue of cross-subsidization between electric and gas ratepayers with respect to certain energy efficiency programs and measures. Section 16-111.5B of the PUA requires measures included in the 2017 Plan to be cost-effective based upon a definition which accounts for both electric and gas savings. The Commission should not, however, accept all measures that pass the statutorily-defined TRC test. Section 16-111.5B(a)(3)(D) of the PUA requires the Commission to also assess whether measures lead to a reduction in the overall cost of electric service or, for example, whether adoption of a measure would require electric customers to cross-subsidize gas customers. Staff Resp. at 11-12.

Staff agrees with NRDC that an individual customer's decision to directly contribute to paying for a measure in order to obtain savings on the customer's gas bills does not imply that electric customers are cross-subsidizing gas customers. Only when the costs the utility incurs and passes along to electric customers exceed the benefits to electric customers (and the measure passes the TRC only because natural gas benefits are included) do electric customers subsidize gas customers. As NRDC correctly notes, "[t]he UCT is a more rational test because it compares only what electric ratepayers would spend to all of the benefits they would receive." NRDC Cmnts. at 2. For these reasons, Staff supports NRDC's proposal that, for purposes of assessing cross-subsidization, UCT test results should be, along with any other pertinent information, reported in future IPA procurement plan filings and be made available to Staff and the parties. Staff Resp. at 12-13.

5. NRDC's Position

NRDC notes that Ameren argues that the 2017 Plan should exclude a program that produces gas savings that are not "incidental" to the production of electricity savings. In its RFP, Ameren used the "only incidental gas savings" standard, defining "incidental" as savings from electric efficiency measures that also save gas (i.e. measures that simultaneously save multiple fuels). Ameren also argues that programs that "produce primarily gas savings" should be rejected – the corollary being that only programs that produce primarily electric savings should be accepted. NRDC opines that this is a different standard because it is possible to have a program that: 1) has only measures that save multiple fuels, but save more gas than electricity, and would therefore be acceptable under an "incidental gas savings only" standard but not under a "primarily electric savings" standard; or 2) has a combination of electric only and gas only measures, but saves more electricity than gas and is therefore acceptable under a "primarily electric savings" standard but not under a "incidental gas savings only" standard. However, as the IPA has made clear, even if one thought it appropriate to use a "primarily electric savings" standard, it should be based on the economic value rather than any measure of energy consumption. NRDC frames its Response to Ameren and Staff Comments in the context of their arguments in favor of an "incremental gas savings only" standard, but states that its response applies equally and just as well (if not more so) to a "primarily electric savings" standard. NRDC Resp. at 1.

NRDC agrees with the IPA that such a standard would be inconsistent with the intent of law. Section 16-111.5B makes clear that its objective is to acquire all residential and small business electric savings that are cost-effective under the TRC test (which assigns economic value to gas saving). Ameren has observed that the all cost-effective efficiency objective of the law has a "…to the extent practicable" qualifier. Ameren further suggests that this qualifier gives the Commission the flexibility to reject programs that produce both electric and gas savings. NRDC argues that it is not clear why procurement of electric savings through a program that provides both electric and gas savings would not be "practicable." NRDC Resp. at 1-2.

NRDC argues even if the Commission disagrees with the IPA's and NRDC's interpretation of the law and agrees with Ameren's and Staff's conclusion that there are conditions under which cost-effective programs that produce gas savings can be rejected, the specific standard for rejecting such programs that both Ameren and Staff are proposing would represent bad policy. The principal argument that Ameren has offered for why the Commission should reject a program that provides both electric and gas savings is that the program "may not look like a good deal for Ameren's electric only ratepayers" if those customers had to pay more for the portion of the program benefits that were associated with electricity savings "than they would to procure comparable supply." NRDC states there are at least two fundamental problems with this argument. NRDC Resp. at 2.

First, NRDC argues that because of the way Ameren defines the "cost of comparable supply" – i.e. excluding avoided transmission and distribution system costs and other electric system benefits provided by efficiency measures – a comparison of electric benefits to the cost of comparable supply will not tell you whether a program is a good deal for electric ratepayers. Put another way, a program can provide more electric benefits than electric costs and still fail Ameren's version of a "cost of comparable supply" test. NRDC Resp. at 2.

Second, NRDC notes that Ameren is not even asking the Commission to adopt a standard for rejecting programs that is based on the cost to procure comparable supply. Instead, it included in its RFP – and wants the Commission to endorse – a standard that would reject any program producing any amount of gas savings that were not "incidental" to the acquisition of electric savings (i.e. through efficiency measures that simultaneously produce both electric and gas savings by the very nature of the measure). That is a blunt instrument for guarding against cross-subsidization of gas ratepayers by electric ratepayers. NRDC Resp. at 2.

NRDC points out that if the Commission believes that it has the legal authority to reject gas programs in order to guard against any cross-subsidization of other fuels by electric ratepayers, it should set the only standard that would ensure that would happen without simultaneously harming electric ratepayers: a requirement that the electric ratepayer benefits exceed electric ratepayer costs. NRDC offers that there is a nationally-recognized energy efficiency cost-effectiveness test which was designed to examine that very question: the UCT. Put simply, if the Commission believes it has the authority and wants to impose a standard to preclude cross-subsidization by electric ratepayers of non-electric savings, the standard should be passing the UCT. NRDC Resp. at 2-3.

NRDC notes that the 2017 Plan references the electric-only TRC in the context of its discussion of Ameren's proposal to reject two programs that were forecast to provide significant gas savings as well as electric savings. NRDC adds that the IPA expresses concern that this proposed rejection is inconsistent with the statute, which (1) requires the IPA to procure all cost-effective efficiency; (2) states that cost-effectiveness is to be determined through the application of the TRC test; and (3) defines the TRC test as including the value of gas avoided costs. The IPA acknowledges that sole reliance on the TRC as defined by statute could potentially lead to adoption of programs in which electric ratepayers were effectively subsidizing gas ratepayers (i.e. if the program costs borne by electric ratepayers were not more than offset by just electric benefits). NRDC agrees with the IPA that the statutory requirement is to include programs that pass the statutory definition of the TRC cost-effectiveness test, and the resulting conclusion that energy savings from both programs should be procured. However, to the extent that a secondary test is required to ensure that cross-subsidization does not occur, the secondary test should be the UCT, not the electric-only TRC. NRDC contends that the issue is that an electric only TRC compares all costs – including both the program costs and the portion of measure costs that are borne by program participants to electric benefits alone. Such a test does not make sense as a means of assessing whether cross-subsidization of gas customers by electric customers is a concern. The program participants' portions of the measure costs have no relevance to such an assessment, and the test is especially skewed if other non-electric benefits (e.g., gas savings) that accrue to those participants are not considered. NRDC opines that the UCT is a more rational test because it compares only what electric ratepayers would spend to all of the benefits they would receive. NRDC Cmnts. at 1-2.

6. IPA's Position

The IPA states that in assessing whether to reject cost-effective programs on the basis of non-incidental gas savings, the Commission has two questions to consider: 1) whether the Commission has the statutory authority to exercise discretion to reject cost-effective programs on this basis; and 2) assuming it has such discretion, whether it should exercise that discretion for the specific proposal at issue in this year's proceeding. Mirroring arguments offered by the IPA last year, the IPA continues to believe that the governing law does not offer the Commission discretion of this nature. But should the Commission conclude that it has the discretion posited by Ameren and Staff, the IPA believes that it would be inappropriate to utilize that discretion to reject the cost-effective behavioral modification program proposal made for the 2017 Plan. IPA Resp. at 15.

With respect to the first question, Section 16-111.5B states that the Commission "shall also approve the energy efficiency programs and measures included in the procurement plan, including the annual energy savings goal, if the Commission determines they fully capture the potential for all achievable cost-effective savings, to the extent practicable, and otherwise satisfy the requirements of Section 8-103 of this Act." 220 ILCS 5/16-111.5B(a)(5). The IPA agrees with Ameren and Staff that the Commission does have some discretion to exclude cost-effective energy efficiency programs under this language—but only if the Commission does not conclude that such a program's inclusion would result in "fully captur[ing] the potential for all achievable cost-effective savings, to the extent practicable, and otherwise satisfy the requirements of Section 8-103 of [the PUA]." In interpreting this language, the IPA believes that the following principles must apply: 1) as it is undefined in the law, the plain language meaning of the term "practicable" (that is, "capable of being put into practice or of being done or accomplished") (Definition taken from Merriam-Webster (www.merriam-webster.com)) must be utilized; and 2) any discretion exercised on the grounds of a program's inclusion failing to be "practicable" must be exercised against the backdrop of language mandating that the Plan "fully capture the potential for all achievable cost-effective savings." The IP claims that because cost-effective energy efficiency programs featuring non-incidental levels of gas savings are still "fully capable of being accomplished" (i.e., "practicable"), and given that their exclusion would result in failing to "fully capture the potential for all achievable cost-effective savings," excluding programs on this basis would be inconsistent with Illinois law. IPA Resp. at 15-16.

While the IPA is not the entity tasked with determining whether to exercise that discretion, the IPA would strongly prefer that Commission Orders approving its procurement plans not be unnecessarily subject to appeal due to reaching conclusions inconsistent with governing law. The IPA has a very strong interest in the stability and integrity of its procurement process, and those principles are undermined when the governing law is disregarded. As a result, the IPA's positions taken in its Plan and in this proceeding are informed by a firm belief that Illinois law should and must be followed, and one role for the IPA in this proceeding is as a zealous advocate for ensuring that the resulting Commission Order follows state law. IPA Resp. at 16-17.

Nevertheless, the IPA acknowledges that in the *2016 Plan Docket*, the Commission adopted a broader view of its discretion, interpreting this language as allowing it to set "practical" limitations on the procurement of cost-effective energy efficiency programs. On this basis, the Commission authorized the rejection of two proposals on the basis of Ameren's new COS analysis developed for that year's submittal. While it is the opinion of the IPA that this determination was inconsistent with the statute, should the Commission feel that this approach affords it broad enough discretion to disqualify programs with non-incidental gas savings, the IPA does not recommend that the Commission do so for the behavioral program included in the 2017 Plan. IPA Resp. at 17.

Turning to that program, the IPA understands and appreciates Ameren's concerns regarding cross-subsidization. Electric ratepayers subsidizing gas ratepayers through the approval of any programs primarily benefitting gas ratepayers is problematic. While the extent to which it can be limited under the Section 16-111.5B paradigm necessitates a close examination of governing law (and not merely an identification of policy concerns, as done by Ameren in its Comments), there are legitimate arguments on both sides. As a result, the IPA would support workshops after the conclusion of this proceeding undertaken in an effort to reach consensus regarding what level of gas savings are permissible in future years' bids. IPA Resp. at 17.

The IPA adds that optimizing program delivery (and thus providing the greatest possible value to ratepayers at the lowest possible cost) may require programs to feature multiple types of savings. To that point, there is no statutory bar against the consideration of dual-fuel programs under Section 16-111.5B, only a requirement that such programs be "cost-effective" when "other quantifiable societal benefits, including avoided natural gas utility costs" are taken into account. *See* 220 ILCS 5/16-111.5B(b); 20 ILCS 3855/1-10. While combining funding from both electric and gas portfolios may be the optimal solution, funding under a Section 8-104 portfolio may not always be available for dual-fuel programs. IPA Resp. at 17-18.

The IPA notes that various parties opine upon on the merits of the UCT, whether as a secondary test to address cross-subsidization by electric customers for benefits received by gas customers or as a secondary test used to further scrutinize cost-effective energy efficiency programs. Staff seeks to have two programs disqualified by the Commission on the basis of a UCT score below 1.0, while ERC seeks to have its program approved despite a UCT score of 0.95 (the program was determined to be cost-effective with a TRC test result of 1.65). Ameren and Staff also contend that Ameren's COS analysis can be utilized for the Commission to disqualify a behavior modification program. While NRDC does not seek to have programs disqualified on the basis of UCT scores, it maintains that the UCT is a proper way to judge the impacts of cross-subsidization and superior to an electric-only TRC. IPA Rep. at 6-7.

The IPA states that only infrequently do these arguments actually reference back to the governing law. This may be because the law makes no mention of the UCT, Ameren's COS test, an electric-only TRC, or any other test other than of the TRC test. It is the IPA's opinion that: 1) the law dictates that the TRC test must apply to the Commission's evaluation of Section 16-111.5B programs; 2) Commission reliance on tests other than the TRC would effectively serve to write the drafters' choice to rely on the TRC out of the law; and 3) any discretion exercised by the Commission in disqualifying cost-effective programs should be limited only to situations where approval of a program would not be "practicable," i.e., the program would be incapable of being put into practice or accomplished, such as when a proposal would be "duplicative" of an existing Section 8-103 program or a Section 16-111.5B proposal. IPA Rep. at 7.

The IPA notes that the governing law directly addresses how the Commission is to weigh the costs and benefits of energy efficiency programs and which costs and benefits may be considered in that analysis. The IPA asserts that Section 16-111.5B requires that programs be "cost-effective," with that definition drawn from Section 8-103 of the PUA (the TRC test). 220 ILCS 5/16-111.5B(b). The statutory definition of the TRC test provides the manner for weighing costs and benefits, expressly and specifically detailing which inputs may be used and compared in its calculation. 20 ILCS 3855/1-10. The IPA explains that the TRC test is best understood as a ledger, with the benefits and costs listed in its definition serving as entries akin to credits and debits, and the final result expressed as a ratio of the two. If credits exceed debits—or benefits exceed costs—the resulting ratio is above 1.0, and the program is cost-effective. IPA Rep. at 7-8.

The IPA explains that the UCT and COS analysis are simply different ledgers in which certain entries present in the TRC are adjusted or deleted. For example, Ameren's COS analysis excludes both gas benefits and transmission and system distribution benefits (which the law requires be considered in a TRC Test), while a UCT does not include societal or gas benefits on one side of the ledger and only looks at utility-incurred costs on the other. Cells on a spreadsheet are deleted to reflect these differences, and outcomes in the ledger change accordingly. IPA Rep. at 8.

The IPA argues that conducting a first review using the ledger required by law (TRC), but then allowing that ledger to be ignored by deleting certain entries for an stricter review (UCT or COS) effectively writes the first ledger out the law. It no longer matters that the governing statute expressly mandates recognition of gas benefits, as a second test is applied which ignores those benefits entirely. Whatever the policy merits of a UCT Test above 1.0, the determination of how a program passes has been made through statute, and an administrative agency cannot simply set state law aside to create new, stricter limitations. *See generally In re Ill. Bell Tel. Co.*, Docket No. 01-0614, 2002 WL 1943561, at 30-31 (finding that the Commission "may not . . . add exceptions and limitations to the statute's applications, regardless of its opinion regarding the desirability of the results of the statute's operation). IPA Rep. at 9.

The IPA adds that the statutory provisions referenced by advocates of utilizing the UCT or COS test (specifically, subsections (D) and (E) of Section 16-111.5B(a)(3)) are clearly not operative on the Commission's review process. Those subsections are requirements for a utility submittal to the IPA, and in no way connect to the Commission's review of energy efficiency programs. More specifically, Section 16-111.5B(a)(3) contains requirements applicable to “each Illinois utility procuring power pursuant to [Section 16-111.5],” and concern what must be included in an assessment provided to the IPA. The statute does not even require that the IPA include those analyses in its submitted plan; it only requires that the IPA include “energy efficiency programs and measures it determines are cost-effective and the associated annual energy savings goal.” 220 ILCS 5/16-111.5B(a)(4)). The IPA asserts that if the analyses under Section 16-111.5B(a)(3)(D)-(E) were intended to inform Commission review of programs, the law would have required those results to be included in the plan. Instead, the statutory provision providing the Commission with guidance on its program review process—Section 16-111.5B(a)(5)—requires only that programs be “cost-effective” (and that the Plan “fully capture the potential for all achievable cost-effective savings, to the extent practicable”), a requirement that Section 16-111.5B expressly traces back to the TRC test (*see* 220 ILCS 5/16-111.5B(b) (directing that cost-effective have the meaning found in Section 8-103); 220 ILCS 5/8-103(a) (stating that “cost-effective” refer to the TRC test)). IPA Rep. at 9-10.

Further, the IPA explains that in addition to being utility requirements and not part of Commission program review, the statutory provisions referenced by advocates of secondary tests weighing costs and benefits (Section 16-111.5B(a)(3)(D)-(E)) may not even refer to the specific test being advocated. For Ameren’s first submittal under Section 16-111.5B in 2012, it applied the UCT to meet the Section 16-111.5B(a)(3)(E) requirement of its submittal to the IPA. For its 2013 and 2014 submittals, consistent with consensus language agreed to by stakeholders in 2013, Ameren used the TRC test for its Section 16-111.5B(a)(3)(E) analysis. It was only in the summer of 2015 that Ameren introduced this new COS analysis; this analysis was found in its July 15, 2015 submittal, developed without any stakeholder input and framed as an “evolution” of its understanding. This COS analysis has only been applied in its submittal in two of the five years in which such submittals have been made. That Ameren’s specific approach is unchangeable or an obvious extension of the statute is flatly contradicted by actual practice under this provision; even today, ComEd utilizes the TRC test to meet its Section 16-111.5B(a)(3)(E) requirement, and no party has ever been found to be non-compliant with this requirement despite the inconsistent interpretations applied to it. It is simply that utility’s choice for its analysis, as that requirement is operative on only the utility—and not on the Commission in conducting program review. IPA Rep. at 10-11.

The IPA understands that the Commission utilized Ameren’s COS analysis in choosing not to include two cost-effective programs in the *2016 Plan Docket*, but the IPA points out that for each prior year for which Section 16-111.5B submittals were made, tests other than the TRC were not used to disqualify proposals even if the resulting ratios fell below 1.0. For instance, in the *2014 Plan Docket*, programs were approved for both Ameren’s and ComEd’s service territories despite a UCT score below 1.0 because each program featured a TRC of above 1.0. *See 2014 Plan Docket*, Order at 87, 89. In the *2015 Plan Docket*, two programs proposed for ComEd’s service territory were approved despite a UCT score below 1.0 because each program featured a TRC of above 1.0. *See 2015 Plan Docket*, Order at 80. The IPA maintains that just as years of past practice were not determinative for the Commission last year, a single year of using a different approach should not be determinative for the Commission this year. IPA Rep. at 11.

Perhaps most importantly, the IPA argues, if the drafters of Section 16-111.5B had sought to have the Commission apply a second test in addition to the TRC in considering incremental energy efficiency programs, they knew full well how to do so. Indeed, they did do so—and then subsequently stripped that language from the law to maintain exclusive focus on the TRC. IPA Rep. at 12.

The fundamental rule of statutory construction is to ascertain and give effect to the General Assembly's intent. *See Michigan Ave. National Bank v. County of Cook*, 191 Ill. 2d 493, 503-04, 732 N.E.2d 528 (2000). The IPA argues that it cannot have been the General Assembly's intent that the Commission would effectively write new requirements and limitations back into the statute, creating a second litmus test after having stripped such a requirement away. Applying a new test to program evaluation beyond the TRC inappropriately writes those changes out of the law, allowing an administrative process to create new limitations that the drafters specifically sought to exclude from the statute. While the UCT, the COS analysis, or an electric-only TRC may present appealing policy arguments, the grounds for their utilization in the Commission's review of proposals stems from a fundamental misunderstanding of the statutory intent of Section 16-111.5B. IPA Rep. at 14.

In connection with this analysis, NRDC expresses concerns related to the IPA's alleged use of an electric-only TRC as the secondary test in its 2017 Plan. NRDC Cmnts. at 1-3. The IPA states that the electric-only TRC calculations were provided in the 2017 Plan for illustrative purposes only. IPA Resp. at 19-20.

7. Commission Analysis and Conclusion

The question here is whether the Commission has the authority to exclude a dual-fuel program that passes the TRC test from a procurement plan, and if so, how that judgment be exercised. The two dual-fuel programs that Ameren recommends not including in the 2017 Plan are discussed below, in Sections V.G. and V. H. of the Order.

As discussed in the *2016 Plan Docket*, the Commission approves cost-effective programs and measures to the extent practicable and the Commission has the authority to use its judgment to set practical limits on the procurement of energy efficiency. *2016 Plan Docket*, Order at 100. Generally speaking, if an energy efficiency program passes the TRC, it should be included in the procurement plan. Staff and Ameren argue that programs that are not primarily focused on electric savings should not be included in procurement plans. Without having been provided a clear definition of when a program would not be primarily focused on electric savings, the Commission will consider dual-fuel programs on a case-by-case basis. The Commission agrees with the parties that in exercising this judgment, the best measure for guiding its determination of whether cross-subsidization exists is the UCT because it only compares what electric ratepayers would spend to all the benefits they would receive. For the most part, however, the Commission agrees with the IPA that if a program passes the TRC, it should be included in the procurement plan.

While the Commission agrees that the UCT will best inform the Commission regarding cross-subsidization, the Commission acknowledges the parties' discussion regarding the COS. The Commission sees no reason for the COS provided by Ameren and ComEd to differ. Apparently, the COS provided by ComEd is consistent with past practice and, indeed, is the same type of COS provided by Ameren up until last year's plan.

The Commission agrees with Ameren that the reason for the PUA's inclusion of the comparison of the cost of procuring additional cost-effective energy efficiency measure to the prevailing cost of comparable supply is because the IPA's function is to procure supply. *See generally* 220 ILCS 5/16-111.5. The IPA does not procure transmission or distribution. The Commission further agrees that that is why Section 16-111.5B(a)(3)(G) requires the utilities to provide "[f]or each expanded or new program, the estimated amount that the program may reduce the agency's need to procure supply." 220 ILCS 5/16-111.5B(a)(3)(G). And this is why the PUA requires a comparison to the "cost of [the] comparable supply" which the IPA will no longer need to procure. 220 ILCS 5/16-111.5B(a)(3)(E). Ameren Rep. at 17. The IPA uses the assessments provided to prepare a procurement plan for Commission approval. 220 ILCS 5/16-111.5B(4). The Commission agrees with the IPA, however, that the statute's directive to the Commission differs and the Commission is required to "approve the energy efficiency programs and measures included in the procurement plan, including the annual energy savings goal, if the Commission determines they fully capture the potential for all achievable cost-effective savings, to the extent practicable, and otherwise satisfy the requirements of Section 8-103 of this Act." 220 ILCS 5/16-111.5B(a)(5). The differences between ComEd's and Ameren's approaches to calculating the COS are not fully explained, thus the Commission cannot say which COS is appropriate. This should be discussed in the SAG and if no resolution is reached, the parties can raise this issue in next year's docket with a more fully developed record regarding the differing approaches by the utilities.

G. Section 9.5.4.2 Demand Based Ventilation Control Program

1. Summary

One of the programs Ameren considers to be inconsistent with its RFP is a demand control ventilation program. Overall, when normalized on a BTU basis, approximately two thirds of the energy reductions come from decreased gas usage—which exceed the level that Ameren considers acceptable and is its basis for not evaluating this program. However, examining savings by dollars saved rather than BTUs shows that two thirds of the financial savings result from reduced electric costs. The TRC results provided by Ameren indicate that the TRC for the program is 1.98, and thus the program is cost-effective. The IPA believes that Ameren erred in excluding this program from its evaluation and includes it in the list of programs that are recommended for approval by the Commission. 2017 Plan at 117.

On August 30, 2016, Ameren filed its next Section 8-103/8-104 Energy Efficiency Plan with the Commission in Docket No. 16-0413. That plan includes demand control ventilation measures that could be viewed as duplicative of this program. The 2017 Plan states that because the Section 8-103 Plan has not yet been approved by the Commission, the IPA does not consider the program to be "duplicative," as no overlapping program has yet been approved by the Commission. However, the Commission may wish to instead approve this program only on the condition that the comparable measures are not approved in Docket No. 16-0413. The IPA further notes that the vendor for this program is also a vendor that was flagged as a potential performance risk in the ComEd review process. 2017 Plan at 117.

2. Staff's Position

With respect to the Demand Based Ventilation Control Program, the supplemental information included by the IPA suggests that the program is cost-effective, with an electric-only TRC ratio above 1.0, even when gas savings are not included. Staff does not, however, recommend relying upon the IPA's reported TRC ratio for the Demand Based Ventilation Control Program and simply approving the program without a closer review. Importantly, the Demand Based Ventilation Control Program is being proposed by a vendor who has failed to perform in Illinois. *See* http://ilsagfiles.org/SAG_files/Quarterly_Reports/ComEd/EPY8/ComEd_PY8_Q4_Report.pdf at 5, 19. The positive TRC results for this program are therefore unreliable. Staff recommends that the Commission reject the Demand Based Ventilation Control Program. 2017 Plan, App. B (Ameren Section 16-111.5B Submittal) at 16; Staff Cmnts. at 15.

3. Ameren's Position

Ameren explains that the Demand Based Ventilation Control Program would be duplicative of programs included in its Section 8-103 plan. Specifically, the program is duplicative of both the Section 8-103 and Section 8-104 portions of a Gas Small Business Direct Install ("SBDI") Program that has been included in Ameren's Section 8-103 program. *See Ameren Ill. Co. d/b/a Ameren Ill.*, Docket No. 16-0413, Ameren Ex. 1.1 at 93 (Aug. 30, 2016). In recognition of that reality, the 2017 Plan now acknowledges that the best way to proceed is a "conditional approval," in which the Commission makes its approval of the duplicative program in this docket contingent—and revocable—based on its decision whether to approve the similar programs in Docket No. 16-0413. When the similar programs are approved in Docket No. 16-0413, Ameren will drop the duplicative program contemplated here from its Section 16-111.5B implementation plans. *See* IPA Plan at 117. Ameren does not object to the approach recommended by the IPA, should the Commission ultimately decide that a conditional approval is necessary in this docket. Ameren Cmnts. at 14.

4. IPA's Position

The IPA concedes that the demand-based control ventilation program may prove to be duplicative of a program proposed by Ameren in its Section 8-103 filing, and thus should only be conditionally approved by the Commission. Further, the IPA understands that parties to that proceeding have reached a stipulated settlement agreement, and thus the demand-based control ventilation program may no longer be a contested matter. IPA Resp. at 14-15.

5. Commission Analysis and Conclusion

It appears that the demand-based control ventilation program is no longer an issue because the parties to Docket No.16-0413 have reached an agreement. Accordingly, this program will be included in Ameren's Section 8-103 and Section 8-104 energy efficiency program and it will no longer be included in the 2017 Plan.

H. Section 9.5.4.3 Behavioral Program

1. Summary

The 2017 Plan states that the other program which Ameren considered to be inconsistent with its RFP was a behavioral program that would be a continuation of an existing program. This bid contained multiple options including maintaining the current program scope or additionally expanding at various levels into all-electric households in addition to continuing the current offering to dual-fuel households. When normalized on a BTU basis, half of the projected energy savings result from reductions in gas usage, but when savings are considered in dollar terms rather than BTU terms, the large majority of the savings result from savings of electricity. 2017 Plan at 117-118.

Although Ameren considered this program "Not Responsive," Ameren still conducted a TRC analysis of this program using both methodologies from the Illinois TRM but excluding the gas savings, as well as using the previously generally accepted methodology for behavioral programs of looking at only one year of savings (a "No Persistence" model). Only the core continuation program (and not the expansion into all-electric homes) was analyzed and the program narrowly failed the TRC under both methodologies. 2017 Plan at 118.

The 2017 Plan explains that while Ameren provided the TRC analysis of the expansion options, it did so by treating them as standalone programs rather than offered in conjunction with the current program. However, the bid specifically described the expansion options as bundled with the core program, and thus the IPA believes they must be evaluated as bundled together. Even excluding gas savings (which, again, the IPA does not believe to be an appropriate methodology), the TRC results of the bundled programs using the TRM methodology are all above 1.0. In addition, while the IPA does not consider Ameren's COS test as a criterion for excluding programs from the 2017 Plan, it notes that the continuation option on its own, or bundled with any of the expansions, does not pass the COS test. 2017 Plan at 118.

2. Staff's Position

Staff recommends the Commission reject the IPA's recommendation because this proposed program consists of two parts, a continuation program targeted to dual-fuel homes and an expansion program offered to electric-only households (which can vary in number based upon which of several expansion program options offered by the vendor is considered). In this instance, the supplemental information presented by the IPA reveals that, standing alone, the expansion program passes both the TRC and COS tests. However, the continuation program is marginally cost-effective only when gas savings are included (with a TRC ratio of 1.07). When gas savings are excluded, the program is not cost-effective, with a TRC ratio of 0.87. The continuation program also, standing alone, fails the COS test. 2017 Plan at 118. Importantly, Staff argues, the continuation program, standing alone, fails the UCT and thus does not satisfy the Section 16-111.5B(a)(3)(D) requirement demonstrating the program would result in a reduction in the cost of electric service. Staff asserts that when the continuation program is included with the expansion program in a bundle, the bundle fails the COS test. In Staff's view the continuation program is not justified based solely upon its electric savings and net benefits. In contrast, the expansion program standing alone is fully justified based upon passing the TRC, UCT and COS tests. Despite this, Staff does not recommend inclusion of the proposed bundle of the two parts of the program. Staff Cmnts. at 16-17.

Staff notes that one part of this program, the expansion program, meets the criteria of the PUA and, in Staff's opinion, the continuation program does not. The part that does not meet the criteria negatively influences the overall ability of the package to meet statutory goals by making the combined programs fail the COS test and reducing the margin by which the programs pass the TRC test. This type of bundled bidding should be discouraged, since it reduces net benefits, and increases the cost of electric service. Finally, excluding the continuation program from the 2017 Plan would not significantly affect energy savings, due to the high level of "persistence" associated with this behavior program. For example, customers who have been in Ameren's behavioral program for many years may save 95% or more of what they can be expected to save under the continuation program, even if the continuation program is excluded from the 2017 Plan. *See* IL-TRMv5.0 Vol. 4 at 16. Staff maintains that ratepayers should not be forced to pay for such minimal incremental energy savings by funding this cost-ineffective portion of the bundled program. Staff Cmnts. at 17.

As an alternative to outright rejection of the program as a whole, Staff proposes that the Commission consider approving only the Expansion Program portion of this proposed program as part of the 2017 Procurement Plan. Under this scenario, Staff recommends the Commission approve the Expansion Program that is projected to produce the greatest level of TRC net benefits. This option would presumably require Ameren to negotiate with the vendor for inclusion of an Expansion Program that is cost-effective and provides net benefits. As with all other approved Section 16-111.5B programs, should the vendor not be interested in implementing the cost-effective Expansion Program only, it would be free to choose to do so after Commission approval. Staff Cmnts. at 18.

3. Ameren's Position

Ameren notes that in Section 9.5.4.3, the IPA advocates for the Commission's approval of a behavioral modification program. The IPA's basis for its request focuses almost exclusively on the TRC test. *See* IPA Plan at 117-119. While it is the IPA's responsibility to include programs that are "cost-effective" for the Commission's review, the Commission analyzes many other factors when determining whether the program, should be included in the IPA Plan. When all the relevant information is considered, Ameren opines that this particular gas-and-electric program should not be approved. Ameren Cmnts. at 16.

Ameren explains that the most recent iteration of this behavioral modification program was approved as a part of Ameren's Plan 3, and it commenced in Ameren Program Year 7. Ameren offered the program in its energy efficiency plan 3 proposal as a combined gas-and-electric program, funded by both the gas and electric budgets derived from Sections 8-103 and 8-104. In the plan 3 approval docket, however, certain parties advocated that the electric component of the program be shifted to the IPA's Section 16-111.5B plan in plan years 8 9. The Commission accepted that recommendation. *See Ameren Ill. Co. d/b/a Ameren Ill.*, Docket No. 13-0498, Order at 62

(Jan. 28, 2014). Ameren states that electric ratepayers have been funding (through Section 16-111.5B) the electric savings accrued through the program, and gas ratepayers have been funding (through Section 8-104) the gas savings. With Ameren's plan 3 ending on June 30, 2017, this program has now bid its combined electric-and-gas behavioral modification program as a Section 16-111.5B program, exclusively. Ameren Cmnts. at 16-17.

Ameren opines that the bid runs afoul of cost-causation principles in that it has electric customers paying for a program that is designed to achieve significant gas savings for gas customers. It also raises significant concerns with respect to whether procurement of the programs will benefit Ameren customers. The bid seeks to continue the dual-fuel program that it currently implements, as well as run an expansion program through one of three options. Critically, the bid makes clear that the baseline continuation program is necessary to run any expansion option. Ameren states that the baseline continuation program does not pass the COS analysis and would therefore cost more to procure than the cost of comparable electric supply. Moreover, while the baseline continuation program is cost-effective when considering both gas and electric savings, the program is not cost-effective for the electric ratepayers who will pay for the program based on the electric benefits that they would be planned to receive. Ameren opines these qualitative analyses reveal that procurement of the baseline continuation program would not be practical nor in the interests of the electric customers who would be paying for it. Because the bid requires the acceptance of the baseline continuation program in order to implement any expansion program, Ameren argues that the bid as a whole should not be included in the 2017 Plan. Ameren Cmnts. at 17-18.

In addition to the foregoing, Ameren notes that stopping this program this year would also be beneficial for energy efficiency in Illinois as a whole. One of the continuing difficulties with evaluating dual-fuel behavioral programs like the ones presented in the bid is that there is limited research available regarding the persistence of the savings achieved. Excluding the behavioral modification program for this next year would give Ameren's independent evaluator an opportunity to measure and analyze the persistence of savings for these types of behavioral programs, which would in turn inform the continued development of the related measures in an updated version of the TRM and, if helpful, in the evaluations themselves. Ameren Cmnts. at 18.

Although Ameren recommends not approving this program, if the Commission does decide to follow the IPA's recommendation, it should include a clear finding that it will be reasonable and prudent for Ameren to collect the costs of the entire program—gas components included—from Ameren electric ratepayers, as the IPA demands.

Ameren argues that the IPA has failed to grapple with the fact, noted by Staff, that when the Continuation Program is included with the Expansion Program in a bundle, the bundle fails the COS test. When the Commission addressed a similar argument last year, the Commission noted that "[w]hile energy efficiency is aimed at reducing the use of energy, little benefit is really achieved on that level, if the cost of avoiding the use of energy exceeds the cost of energy, which is how the dictionary definition of 'efficiency' was used above." *2016 Plan Docket*, Order at 103. The combined program's failure to pass the COS analysis provides a sensible basis for its exclusion, and it must also be noted that the combined program fails the electric-only UCT. Ameren Rep. at 19-20.

Further, Ameren suggests, the IPA failed to respond to the concerns, raised primarily by Staff, regarding whether any of the expected savings claimed by the bidder associated with the Continuation Program would ever actually materialize. In short, the Continuation Program may be an even worse deal than it already appears, rendering the entire bundled bid an unattractive option. Ameren stresses that the IPA never responded to this important point, which in and of itself is grounds to reject the bid. *See Crossroads Ford Truck Sales v. Sterling Truck Corp*., 959 N.E.2d 1133, 355 Ill. Dec. 400, 2011 IL 111611, ¶ 63 (Ill. Ct. App. 1st Dist. 2011) (failure to respond in plaintiff's reply brief to the substance of an argument raised by the defendant in its response brief meant plaintiff forfeited the argument). Ameren Rep. at 20.

In summary, Ameren claims that there are numerous compelling reasons for the exclusion of the behavioral modification program from the 2017 Plan, many of which the IPA has not refuted, and the Commission should exclude this program. Ameren Rep. at 21.

4. AG's Position

The AG supports the rejection of this bid for this procurement year. While the AG supports the recognition of gas and all other benefits in the evaluation of the cost-effectiveness of an IPA program bid, the AG sees value in examining the veracity of the most recent TRM-reported savings' persistence of the behavioral program at issue here – especially given the reported program design in this particular bid, which includes sending the behavioral reports to the same customers that have received them in the past. The AG recommends that this particular bid be excluded from the 2017 Plan so that independent evaluators can assess the persistence of the program over a single year when the program is not being provided. In doing so, the AG recommends that the Commission include a directive to Ameren that requires it to conduct an evaluation on a timely basis and follow procedures regarding the development and review of EM&V work plans that are consistent with the Illinois Energy Efficiency Policy Manual. AG Resp. at 11-12.

5. NRDC's Position

NRDC states that Staff argues that programs which have two or more components and which are cost-effective only when the components are bundled together (i.e. with the cost-effectiveness of one component being enough to offset the lack of cost-effectiveness of the other) should be discouraged because such "bundling" reduces net benefits. This proposal is fundamentally flawed because it ignores the often critically important connections between different components of a program. NRDC opines that bundling of efficiency program components would only reduce net benefits or increase the cost of electric service, as Staff has argued, when the bundled program components are truly separable – i.e. when the cost-effectiveness of each component is not affected by whether it is bundled with the other component(s). NRDC Resp. at 3. NRDC recommends inclusion of this program.

6. IPA's Position

As a threshold matter, the IPA believes that the behavior modification program is best evaluated as bid by the bidder itself. This "as bid" approach requires both: a) the continuation of the existing plan year 9 program; and b) the choice of one of multiple expansions into all-electric households (further increasing the focus on electric savings specifically). While this bidder created self-inflicted confusion through assembling its bid in this oddly segmented manner, the language of the bid makes sufficiently clear that the "expansions" are not proposed as standalone programs, and should be analyzed in conjunction with the "continuation." To maximize participation, the IPA chose the largest of the available expansions for inclusion, and the resulting program featured a TRC test result of 1.17. IPA Resp. at 18.

As explained in the Plan, when normalized on a BTU basis, half of the projected energy savings result from reductions in gas usage. But when savings are considered in dollar terms (i.e., the focus is on benefits), a significantly higher proportion of benefits accrue to electric ratepayers than gas ratepayers despite the presence of non-incidental levels of gas savings. As these programs primarily benefit electric ratepayers, not gas ratepayers, the IPA believes that if the Commission indeed has the discretion to disqualify programs on the basis of non-incidental gas savings, exercising that discretion over this program would not be in the best interest of electric ratepayers and the behavior modification program should remain in the Plan. IPA Resp. at 18-19.

The IPA submits that while parsing the program as recommended by Staff (i.e., evaluating and approving only the expansion) may be attractive insofar as the expansion appears to be the stronger component, it is unclear whether the expansion standing alone would feature a different cost structure or necessitate a different program design if not coupled with the continuation (as was originally bid). This underscores one of the challenges of manipulating bids after their receipt, an approach also suggested by the AG in its Comments: the bidder is far more knowledgeable about the impacts of bid modifications than any party or the Commission itself. The IPA notes that without increased participation from the bidders themselves (an ongoing concern highlighted by the IPA in Section 9.4.2 of the 2017 Plan), the full implications of those choices are unknowable to the parties in this docket. Given that the bid as originally presented and constructed is cost-effective and that the strongest arguments exist for adopting the largest proposed expansion, the IPA believes the program should be evaluated and approved consistent with its approach taken in the Plan and need not be parsed as recommended by Staff. IPA Resp. at 19.

The IPA opines that utilizing Ameren's COS test as grounds for disqualification would essentially write the TRC out of the statute in favor of the policy preferences of Ameren and Staff. As this is not a tenable interpretation of Section 16-111.5B, Ameren's COS test is not a valid basis for disqualifying those programs, and the IPA argues that they must be approved as currently proposed in the 2017 Plan. IPA Rep. at 14-15.

The IPA notes Staff's concern regarding the persistence of past program participants' energy savings. Although the IPA appreciates the desire to gain additional information and knowledge regarding this type of behavioral program, using that desire to exclude this program is misguided. As the IPA noted in its Response regarding the Community-Based LED program, "the IPA believes it would be inefficient to require new program designs to shut down after one year to await evaluation results simply because the efficiency of the approach is not yet known." IPA Resp. at 20. That same logic applies here: if this program was shut down to examine persistence, several years may elapse before evaluations are concluded, a new RFP issued, a program approved by the Commission, and then a program restarted. Potential vendors would presumably be cautious in proposing a new program given this past experience and delay. Previously non-participating all-electric homes (who by their very nature have higher electric usage, and costs) would be deprived of the new opportunity to participate and save energy and money. IPA Rep. at 16.

The IPA notes that on October 18, 2016 the American Council for an Energy-Efficient Economy ("ACEEE") published "Behavior Change Programs: Status and Impact," a survey and analysis of the effectiveness of a wide range of types of behavioral energy efficiency programs. This report examines 20 dual-fuel home energy report programs (the type of program at issue here) as well as 21 electric home energy report programs and six gas home energy report programs. While the IPA has not conducted an exhaustive review of the report, the IPA states that behavioral energy efficiency programs have been extensively researched and evaluated (including two studies in the Ameren service territory, one in the ComEd service territory, and one for The Peoples Gas Light and Coke Company). IPA Rep. at 16.

According to the IPA, while the ACEEE report does acknowledge an ongoing need to study persistence, further analysis does not necessitate ceasing the behavioral program's operation. Instead, to the extent that the Commission determines that persistence in behavioral program energy savings needs to be further evaluated, a superior approach than rejecting the program to study its persistence would be to approve the program and have a randomized group of current participants discontinued (and replaced by other dual fuel customers to maintain the proposed overall participation level), with the discontinued participants' savings persistence studied. The IPA submits that this approach would allow for capturing ongoing benefits of the program for existing customers, the expansion of the program to new all-electric customers and the new research and evaluation opportunities sought by Ameren and the AG. IPA Rep. at 17.

7. Commission Analysis and Conclusion

The Commission declines to approve the inclusion of this behavioral program as bid in the 2017 Plan. The Commission finds that this program should be excluded from the 2017 Plan so that the independent evaluator can assess the persistence of the program savings over a single year when the program is not being provided. Moreover, the Commission notes that Staff states that excluding the continuation program from the procurement plan would not significantly affect energy savings, due to the high level of persistence associated with this behavioral program. For example, Staff explains, customers who have been in Ameren's behavioral program for many years may save 95% or more of what they can be expected to save under the continuation program, even if the continuation Program is excluded from the procurement plan. *See* Staff Cmnts. at 18 (citing IL-TRMv5.0 Vol. 4 at 16). For these reasons, the Commission does not approve this energy efficiency program because it is not clear that it will "fully capture the potential for all achievable cost-effective savings, to the extent practicable." 220 ILCS 5/16-111.4B(a)(5).

Staff offers the option that just the expansion portion of this bid be approved, although it is not clear whether the bidder would consider separating the continuation and expansion programs. If it is a possibility, the Commission agrees with Staff that the expansion program should be included in the 2017 Plan because it clearly passes the TRC test.

Finally, the Commission will not adopt a rule against bundled bids as suggested by Staff because each program could be structured so differently that it is impossible to say that all bundled bids are improper.

I. Section 9.5.5 Duplicative Programs

1. Summary

In the *2014 Plan Docket*, significant consideration was given to how to address third-party program bids that may be "duplicative" of existing programs under Section 8-103 of the PUA. Based on prior plans, the IPA understands the term "duplicative" to mean a program that overlaps an existing program in a manner in which greater market participation by vendors does not yield sufficient additional value to consumers. Alternatively, while a "competing" program may occupy the same general space, "competing" programs may benefit from multiple delivery channels. The general goal would be that "duplicative" programs are to be avoided, while "competing" programs would be acceptable to the extent that the competition does not render one or both programs non-cost-effective. 2017 Plan at 119.

The 2017 Plan states that because Section 8-103 programs have not yet been approved by the Commission, no proposed Section 16-111.5B program can be considered "duplicative" of any existing Section 8-103 program. However, as previously explored by the Commission in the *2015 Plan Docket*, two proposed Section 16-111.5B programs may indeed be "duplicative" of one another based on application of the criteria above, thus forcing a clear choice between overlapping programs or some other corrective action intended to safeguard against the erosion of customer value. 2017 Plan at 120.

For the 2017 Plan, the issue of duplicative programs arises when considering small business bids received in response to this year's RFP. Of the eight small business programs that passed the TRC, six of the programs had varying degrees of overlap in their offerings. For the six programs that did have varying degrees of overlap, Ameren assessed the programs' scope and prior experience with the vendors to recommend that one of the programs not be included. The remaining five bids were deemed sufficiently distinct such that they do not create issues of duplication. The Small Business Whole Building program overlaps all of these other programs, and in Ameren's assessment, including it along with the other programs would violate the duplicative test. The 2017 Plan adopts Ameren's recommendation to exclude the "duplicative" Small Business Whole Building program. 2017 Plan at 120.

The 2017 Plan also recognizes that in the Section 8-103 plan currently under consideration in Docket No. 16-0413, Ameren has included an SBDI program. As noted in the discussion of the Demand Based Ventilation Control in Section 9.5.4.2, because that program has not been approved by the Commission, the SBDI program proposed under Section 16-111.5B cannot be considered "duplicative" of the Section 8-103 SBDI program. To mitigate any such concerns, however, the 2017 Plan recommends that the

Commission consider offering only conditional approval of the SBDI program in this Plan, contingent on the SBDI program not being approved in Docket No. 16-0413 and with the rejection of the program proposed here contingent on Ameren (or other stakeholders) demonstrating that if the duplicative screening criteria were applied, the Section 16-111.5B program would in fact be duplicative of the Section 8-103 program. 2017 Plan at 120.

2. AG's Position

The AG agrees with the 2017 Plan that because Section 8-103 programs had not yet been approved (or even formally proposed) at the time Ameren provided its submittal to the IPA, no proposed Section 16-111.5B program can be considered duplicative of any existing Section 8-103 program. The IPA offers one solution to the issue of duplicative programs, and in particular related to a bid for a SBDI l program that the IPA suggests may be duplicative: potential conditional approval of the SBDI program if the Commission approves an Ameren-sponsored SBDI program in its Section 8-103 program filing in Docket No. 16-0413. 2017 Plan at 120. The AG urges the Commission to reject that proposal. The SBDI program at issue in this docket is not duplicative of Ameren's proposed SBDI program, which has not yet been approved. Even if it is approved under Section 8-103, the Commission should not reject a similar program here. At worst, it would constitute an expansion of an approved SBDI program. However, given the open-ended RFP utilized by Ameren, and the fact that no Section 8-103 SBDI program yet exists, it is the Section 8-103 program that would qualify as an expansion of the IPA portfolio program, not the opposite. AG Cmnts. at 11-12.

3. Ameren's Position

During the informal comment process, Ameren identified the SBDI Program which was bid for inclusion in this year's IPA energy efficiency procurement as duplicative of the Section 8-103 portion of the SBDI Program included in Ameren's Plan 4, noting that it should no longer be recommended to the Commission for inclusion in the Section 16-111.5B Plan. *See* Docket No. 16-0413, Ameren Ex. 2.0 at 13-16 (Aug. 30, 2016). The IPA now suggests that the Commission can take the conditional approval approach to this program as well, offering approval "contingent on the SBDI program not being approved in Docket No. 16-0413." 2017 Plan at 120. If, on the other hand, the SBDI program is approved in Docket No. 16-0413, then the program will not be procured pursuant to Section 5/16-111.5B. Ameren does not object to this approach. Ameren Cmnts. at 18-19.

In light of the stipulation filed in Docket No. 16-0413 (AG Ex. 1.3), which resolves the contents of Ameren's Plan 4, Ameren would now request that the SBDI program (as well the 360 Energy and GDS programs identified in Table 6 to the stipulation filed in Docket No. 16-0413) be conditionally approved as programs that are incremental to Ameren's Plan 4 SBDI programs, subject to the Commission approving a Plan 4 that is consistent with the stipulation. Ameren Resp. at 18-19.

As noted by other parties, there are no remaining disputes that the Commission must resolve with respect to duplicative determinations, as they pertain to Ameren. This point appears to be uncontested. *See* IPA Resp. at 14-15.

4. IPA's Position

As the IPA understands the settlement, the SBDI program at issue in this proceeding would now be an expansion of the Section 8-103 SBDI program and thus should be approved. While not a party to the stipulation, the IPA has reviewed the stipulation, and to the extent that aspects of the stipulation apply to the 2017 Procurement Plan's inclusion of small business programs, the IPA does not object to those parties' proposals. IPA Rep. at 20.

5. Commission Analysis and Conclusion

Due to the stipulation in Docket No. 16-0413, it appears that there is no longer a dispute regarding the SBDI program. The Commission adopts the resolution reached by the parties to treat the SBDI Program as an expansion of Ameren's Section 8-103 SBDI Program.

J. Section 9.5.6 Additional Conditions Requested by Ameren Illinois

1. Summary

The 2017 Plan notes that Ameren raised additional issues with three programs and requested that additional conditions be applied to their approval. For the Residential Retail Lighting program, Ameren noted that LED prices are dropping, and therefore requested that since the bid was for three years, it should be granted the ability to reopen the contract on an annual basis to review product type, product quantity and price to ensure the customer is achieving a good value through the program. Given the dynamic nature of the lighting market, the 2017 Plan grants Ameren's request. 2017 Plan at 121.

For the Community LED Distribution program which proposes to distribute LEDs through food pantries, Ameren raised concerns regarding the number of bulbs to be distributed per household (the program builds off a current year program which is distributing CFL bulbs), the relative newness (in Ameren's service territory) of the distribution approach, and the ongoing reduction of prices for LED bulbs. Due to these concerns, Ameren requested that the program only be approved for one year (rather than three years as bid) to allow Ameren to assess the similar CFL distribution program currently underway. The 2017 Plan states that, while the IPA appreciates Ameren's concern, an alternative approach could be to apply to this program a similar condition that is applied to the Residential Retail Lighting program, and it is unclear to the IPA how the pay-for-performance nature of Section 16-111.5B contracts would fail to safeguard ratepayers against any failures in these program design approaches. 2017 Plan at 121.

For the Low Income Multifamily program, Ameren notes that the vendor is currently supporting Department of Commerce and Economic Opportunity ("DCEO") programs. The RFP includes a condition that "[i]f an IPA bidder later works under the Ameren [Section 8-103] Plan as either a contractor or subcontractor, a clear separation of duties and costs will be required under the Ameren contract." Ameren suggests extending that concept to encompass work for DCEO in order to prevent future unfair bidding advantages. While separation of duties appears to be a reasonable concept, the IPA notes that given the fact that DCEO does not have an approved future Section 8-103/8-104 portfolio, it is unknown at this time if this vendor will continue to be a DCEO contractor in the future. 2017 Plan at 121.

2. Ameren's Position

Ameren notes that the IPA continues to disagree with Ameren's proposal to limit the Community LED Distribution Program to one year, rather than three years. *See* 2017 Plan at 121. The IPA proposes to treat the Community LED Distribution Program in the same way as the Residential Retail Lighting Program, granting Ameren the ability to reopen the contract on an annual basis to review product type, product quantity and price to ensure the customer is achieving a good value through the program. *See* 2017 Plan at 121. But, the dynamics of the two Programs are not identical. Ameren Cmnts. at 20-21.

Ameren's concern regarding the Residential Retail Lighting Program relates to the fact that LED prices are dropping continuously, which means the marketplace will need to be reviewed to ensure the program is performing as intended. Ameren is not concerned that there will be a need for a new program design. Ameren Cmnts. at 21.

On the other hand, Ameren has two concerns regarding the Community Based LED Distribution Program. The first relates to whether the current Community Based CFL Distribution Program, approved in the 2016 Plan and being implemented during plan year 9, will achieve market saturation at the targeted segment such that the Community Based LED Distribution Program essentially becomes duplicative and, accordingly, not needed beyond the first year of its bid. The second relates to the specifics of the program design. The program design needs to be evaluated by the independent evaluator to gather meaningful and reliable information on the amount of product leakage to regions not served by Ameren, whether the product is actually being installed, and what technology (CFL or incandescent) is being replaced. Ameren Cmnts. at 21.

The difference is that, in the former scenario, Ameren may need to intervene and re-negotiate some pricing provisions to ensure that the program operates in a manner that is in the interest of customers, while, in the latter scenario, Ameren is concerned that, due to market behavior and evaluator feedback, the vendor should revise their program design and re-submit the program in subsequent IPA procurement processes. In short, Ameren recommends that the Commission order the IPA to revise the 2017 Plan so that the Community LED Distribution Program is limited to one year. Ameren Cmnts. at 21.

Ameren notes that the IPA has now expressed that Ameren's proposal approach is acceptable. IPA Resp. at 21. As such, Ameren requests that the Commission order a modification of the 2017 Plan consistent with Ameren's request. Ameren Rep. at 22.

3. IPA's Position

Ameren recommends that the Community Based LED program be limited to one year rather than three years as proposed by the bidder. After reviewing both the initial submittal and the comments on the Draft Plan, the IPA suggested an alternative approach that, while keeping the 3-year program length intact, would expressly allow Ameren to reopen the contract on an annual basis. 2017 Plan at 121; IPA Resp. at 20.

This program (and its CFL-based predecessor) distributes bulbs to households through Food Banks and gives each participant four bulbs. The IPA states that families rely on Food Banks in times of financial hardship; some families only rely on the essential services of a Food Bank for a limited time period, while others may have to do so for longer. It is not a static population. Over the one-year CFL program and the proposed three years of the LED program, there may be families that only receive bulbs from the program once or twice, while others may have more opportunities. The portion of a household's lighting served by this program therefore will inherently vary, but the IPA believes that it is unlikely to reach saturation. IPA Resp. at 20.

While Ameren does raise valid concerns about the need to evaluate this program and its impact, those concerns arguably apply to any new program design. The IPA believes it would be inefficient to require new program designs to shut down after one year to await evaluation results simply because the efficiency of the approach is not yet known. Further, because the bidder will have already invested the organizational resources to develop relationships with the Food Banks in the Ameren service territory in implementing the CFL program (and those relationships would presumably carry over to the LED program with little incremental cost), the program may be expected to operate more effectively and efficiently in each year after its initial startup. IPA Resp. at 20-21.

The IPA appreciates the concerns raised by Ameren, and notes that it did not explicitly reject Ameren's recommendation to approve the program for only one year. Instead, the IPA simply offered an alternative approach. The IPA believes the alternative approach to be preferable, but either outcome would be acceptable. IPA Resp. at 21.

4. Commission Analysis and Conclusion

The Commission agrees with the IPA that it would be inefficient to require new program designs to shut down after one year to await evaluation results simply because the efficiency of the approach is not yet known. In particular the Commission is concerned that the bidder will have invested organizational resources to develop relationships with the Food Banks in the Ameren service territory to implement this program. Moreover, the Commission notes favorably that the program may be expected to operate more effectively and efficiently in each year after its initial startup.

Also, the Commission agrees that the pay-for-performance nature of the program should protect ratepayers. Therefore, the Commission finds the alternative proposed in the 2017 Plan to be acceptable. That approach recognized that the bid was for three years, but that Ameren should be granted the ability to reopen the contract on an annual basis to review. This is adopted by the Commission.

K. Section 9.5.8 Ameren Illinois Reservations and Requested Determinations

1. Summary

The 2017 Plan states that Ameren, in its filing, made the following reservation:

> AIC reserves the right to update, revise, amend or end the programs approved in this docket. AIC's positions reflected herein are subject to change and AIC reserves the right to adjust any terms or conditions with any selected implementers to account for its upcoming Section 5/8-103 and Section 5/8-104 integrated energy efficiency and demand response Plan 4 filing, any pertinent ICC Orders, including those addressing customer data and privacy, or other relevant matters.

2017 Plan at 122. The 2017 Plan notes the challenges created in the timing lag between the approval of Section 16-111.5B programs in the 2017 Plan and the ongoing Section 8-103 and 8-104 proceeding, but the IPA is nevertheless concerned that bidders had a reasonable expectation that the provisions of the RFP would be applicable to the consideration of their bids, and after the fact changes could have an impact on their desire to move forward and implement their proposed programs. 2017 Plan at 122.

The 2017 Plan further notes that Ameren also made the following request:

> AIC may seek approval of programs as part of its Section 5/8-103 and Section 5/8-104 Plan that would render certain programs to be approved as a part of the Procurement Plan duplicative, and may seek conditional findings in this docket to provide for such an outcome.

2017 Plan 122-23. The 2017 Plan states that the IPA has concerns related to this request because it appears to change the playing field for bidders after the fact by allowing a participating utility to receive bids under an open-ended RFP, but then to potentially shape its Section 8-103 portfolio so as to disqualify certain third-party bids after their receipt and analysis. According to the 2017 Plan, it is unclear at this time how this reservation of rights will be applied by Ameren. 2017 Plan at 122-23.

2. Ameren's Position

Ameren states that it issued a transparent RFP that informed bidders of the misalignment of timing between Section 16-111.5B and Sections 8-103 and 8-104, as well as its potential impact on the bids. *See* Draft Plan, App. B-App. 3_Final.pdf (AIC RFP) at 8. Ameren submits that the bidders acknowledged and accepted this reality when they responded to the RFP. Ameren argues that the reasonable expectation of the bidders at the time they placed their bids wholly aligns with Ameren's requested reservation in its submittal, and there should be no impact whatsoever on the bidders should their programs be approved or rejected. Ameren Cmnts. at 22.

Ameren explains that it conducted its RFP process for the IPA energy efficiency procurement in tandem with the development of its Section 8-103 and Section 8-104 Plan 4 as part of a holistic approach which was made clear to all stakeholders involved in the SAG Plan 4 Planning process, and as a part of the SAG IPA Subcommittee workshops, in which the IPA participated. Ameren notes, neither the submission of a bid nor the discussion of that bid in a utility's submittal creates any sort of legally enforceable expectation that the bid will ultimately be accepted, particularly because it is well known that the cost-effectiveness analysis must still be completed and verified by the IPA, and because other practical considerations go into the Commission's bid analysis. Ameren claims its process was vetted and approved as a consensus item by the SAG IPA Subcommittee, including the IPA itself. *See* 2016 SAG Report at 6-7; Ameren Cmnts. at 23.

Ameren posits that the PUA allocates this risk onto bidders in the IPA electric energy efficiency procurement process, not onto the utilities. Ameren asserts that the PUA is currently constructed in such a way as to allow for the simultaneous development of the utilities' Section 8-103 and 8-104 portfolios and the IPA's incremental electric energy efficiency procurement every three years. Under those circumstances, some bids for inclusion in the utilities' Section 8-103 portfolios will overlap with some bids for inclusion in the IPA electric energy efficiency procurement process, especially because the bids in each category are generally developed with reference to the same Potential Study. Because duplicative programs are disfavored, Ameren maintains, there must be some flexibility in the regulatory process to ensure that ratepayers are protected. Ameren Cmnts. at 23.

Ameren opines that the best way to protect ratepayers consistent with the PUA is through the regulatory approval process for those programs procured through the IPA electricity procurement process. The PUA only provides for the procurement through the IPA process of "new or expanded cost-effective energy efficiency programs or measures that are incremental to those included in energy efficiency and demand-response plans approved by the Commission pursuant to Section 8-103" of the PUA. *See* 220 ILCS 5/16-111.5B(a)(3)(C). Thus, as a matter of law, IPA programs which are duplicative of savings to be achieved by Section 8-103 (or Section 8-104) plan programs—and therefore not incremental—do not qualify for inclusion in the IPA plan approved by the Commission. Ameren Cmnts. at 24.

Ameren states that parties spent hundreds of individual hours working on this process, which culminated in a consensus document. Ameren needed to know that it could navigate the chronological complexity of this year's procurement processes without needless criticism from the stakeholders, so it circulated its draft RFP among stakeholders, collected feedback from them, and incorporated their feedback where appropriate, just as the Commission directed Ameren to do. *See* 2016 SAG Report at 6-7. Critically, Ameren states, no stakeholder raised these concerns about Ameren's reservation of rights at that time. Now, the AG has abandoned the consensus attained in the SAG regarding Ameren's RFP process. *See* AG Resp. at 14-15. NRDC has functionally done the same thing. NRDC Response at 4-5. Ameren asserts that if the SAG consensus is to be meaningless, then parties will have no incentive to participate in SAG workshops. Ameren Rep. at 23-24.

Ameren maintains that there is simply no basis, in the PUA, in Commission precedent, in Illinois case law, or anywhere else, for a directive ordering the utilities to build their Section 8-103 portfolios around the bids for the IPA's energy efficiency procurement every three years. Ameren recommends that the Commission order the IPA to strike its criticism of Ameren's reservation of rights. Ameren Rep. at 24-25.

3. NRDC's Position

NRDC acknowledges the challenges of the timing of IPA procurement and 8-103 plan approval processes, but does not share Ameren's interpretation of the law. The law is clear that the IPA programs must be incremental to Section 8-103 approved programs, not to programs that utilities have submitted for approval. Moreover, NRDC does not see why it is a problem to have IPA program bids limiting what can be included in proposals for future Section 8-103 programs. NRDC notes that if a program is included in the IPA's procurement plan instead of in a utility's Section 8-103 portfolio, it effectively frees up Section 8-103 funds that can be allocated to other programs. This will lead to greater cost-effective efficiency savings because, unlike the IPA Procurement Plan, Section 8-

103 portfolios are subject to total budget caps. NRDC opines that retroactively rejecting program proposals because a utility decides after an RFP has been issued to run its own similar program is bad public policy. NRDC Resp. at 5.

In the end, because of the settlement reached in Ameren's Section 8-103 plan between Ameren, NRDC and other parties that would have Ameren both run an SBDI program in its Section 8-103 portfolio and support what would be treated as an "expansion" of that program through the IPA at budget and savings levels consistent with those bid by several vendors for the current IPA procurement process, the NRDC does not think that this is an issue in this proceeding anymore. However, NRDC is of the opinion that the policy proposal put forward by Ameren should not be adopted because of the adverse effects it could have in the future. NRDC Resp. at 5-6.

4. AG's Position

The AG shares the IPA's concern with Ameren's open-ended request to declare a program duplicative. In the AG's opinion, this request runs contrary to the open-ended nature of the Ameren RFP, which indicated to bidders that no Section 8-103 programs were in place for the relevant time period. The AG asserts that the Commission should expressly exclude such language in any IPA plan, and prohibit its inclusion in future RFPs. Such language, if approved, would likely dissuade potential vendors from taking the time to prepare an RFP, if not incent vendors to include additional costs as a way to limit financial risk from unexpected changes in the bid review process. AG Cmnts. at 12-13.

The AG notes that Section 16-111.5B(a)(2) provides that the IPA's Plan "shall also include an assessment of opportunities to expand the programs promoting energy efficiency measures that have been offered under plans approved pursuant to Section 8-103 of this Act or to implement additional cost-effective energy efficiency programs or measures." 220 ILCS 5/16-111.5B(a)(2). According to the AG, a conundrum exists every three years, when the IPA energy efficiency procurement plan is approved prior to the next Section 8-103 three-year energy efficiency portfolio standard plan making the identification of "expansions" of existing Section 8-103 programs that have not yet been approved challenging. *See generally* 220 ILCS 5/16-111.5B(a); 220 ILCS 5/8-103(a)-(f); AG Resp. at 12.

The AG notes that the Commission directed the IPA, utilities and stakeholders to engage in IPA workshops to attempt to reconcile the how solicitation of IPA bids should work when the Section 8-103 programs for the next three-year energy efficiency plan have not yet been approved. The AG stresses that as the 2016 SAG Report details, a solution was crafted. It states that "ComEd placed the Residential Lighting, Home Energy Reports and [SBDI] programs into the Section 16-111.5B IPA Procurement Plan process, effectively setting their Section 8-103 … program sizes to zero and using the IPA to capture all cost-effective opportunities to "expand" these programs. ComEd's rationale is that these 'expanded' programs would be otherwise unduly constrained under [Section 8-103]." 2016 SAG Report at 7. Ameren, on the other hand, used an open-ended RFP that included no specific direction regarding program content, and informed bidders that no Section 8-103 programs were yet in place. In its Comments, Ameren requests that the Commission order the 2016 SAG Report language be included in the 2017 Plan (or make clear that the language in the 2016 SAG Report, which documents consensus items from the workshops), is approved in the Commission's Order. Ameren Cmnts. at 5; AG Resp. at 13-14.

The AG notes that Ameren's language, which is a consensus position in the 2016 SAG Report, requires further clarification in light of the wording of the Ameren RFP, the bid results, and Ameren's proposed portfolio of programs that it filed in its Section 8-103 approval proceeding, Docket No. 16-0413. The AG explains that in this case a vendor proposed a three-year SBDI program of a certain size for the IPA portfolio. Ameren then included an SBDI program in its Section 8-103 filing, at a considerably smaller projected savings level and budget amount. If the Commission simply adopts the proposed Ameren language as a consensus policy, and the IPA's suggestion that the SBDI program be approved conditionally, subject to rejection of a similar Ameren program in Docket No. 16-0413, it is clear that this opportunity for a cost-effective SBDI program will be lost because the program could be identified as duplicative, retroactively. AG Resp. at 14-15.

The AG states that while Ameren and the AG, ELPC, NRDC and CUB reached a stipulation in Docket No. 16-0413 that would treat the IPA SBDI program at issue as an expansion of the Ameren 8-103 SBDI program, the fact remains that the language highlighted would permit the potential inequity – a cost-effective bid deemed duplicative retroactively due to a utility's decision to offer the same program in its Section 8-103 portfolio – to arise again in the future. Hence, clarification by the Commission on this point is crucial. The AG submits that unless clarified, approval of this language would permit a utility to issue an open-ended bid that informs potential bidders that no programs yet exist in the utility's Section 8-103 portfolio, but then later declare that a cost-effective bid be declared "duplicative" because the utility chose to propose the same program (and on a smaller scale) in its Section 8-103 filing. AG Resp. at 14-15.

5. IPA's Position

The IPA disagrees that its commentary should be stricken from the 2017 Plan, as this commentary highlights a legitimate concern with Ameren's approach to constructing its Section 8-103 portfolio. In this proceeding, the IPA and Ameren have no known disagreement over any proposal contained in Ameren's Section 8-103 portfolio that currently renders one of its Section 16-111.5B programs as duplicative. For instances in which a duplicative designation has been offered by the utility, the IPA has agreed that only conditional approval would be appropriate. Nevertheless, the IPA maintains that its commentary highlights an important concern with Ameren's approach of reserving its right to modify its Section 8-103 portfolio in light of bids received pursuant to Section 16-111.5B, which could possibly render otherwise permissible bids duplicative well after submission. The IPA points out that ComEd chose to move several programs wholesale at scale into the Section 16-111.5B portfolio as expansions. Thus, the IPA explains that bidders knew that programs of those types would be duplicative and were on notice not to offer such bids. By comparison, bidders responding to Ameren's RFP would have no notice of what program types could potentially result in "duplicative" bids, and all programs would stand at an unknowable risk of being disqualified. IPA Resp. at 21-22.

The IPA states that this is not to say Ameren necessarily must adopt ComEd's approach; it is merely that, in the its opinion, Ameren's approach carries a downside for potential bidders. Because that downside is accurately and appropriately captured in the IPA's commentary, and because Ameren's approach would effectively offer it inappropriate veto power over third-party bids intended to be reviewed on the basis of their merits, the IPA maintains that this commentary should not be stricken from the 2017 Plan. IPA Resp. at 22.

6. Commission Analysis and Conclusion

The Commission notes that with respect to the current IPA plan and the current Section 8-103 plan, there is no longer a dispute regarding energy efficiency programs because of the settlement reached by the parties in the Section 8-103 docket. However, the parties request that the Commission address Ameren's RFP process in advance of the next three year cycle.

The Commission agrees with the AG and the IPA that utilities should clearly indicate in the RFP what program they intend to propose for inclusion in their Section 8-103 plan. In other words, the Commission finds that ComEd's process provided a clearer picture for bidders.

Ameren states that its RFP process was vetted and approved as a consensus item by the SAG. Ameren Cmnts. at 23. The 2016 SAG Report states the following:

> For third-party programs that would duplicate programs Ameren Illinois plans to propose for inclusion in its Section 8-103 / 8-104 Plan, Ameren Illinois may request that the potentially duplicative third-party program only be conditionally approved or approved with conditions pursuant to Section 16-111.5B in the event that the Commission does not approve a duplicative Section 8-103 / 8-104 program in Ameren Illinois' Section 8-103 / 8-104 Plan proceeding.

2016 SAG Report at 6-7. The Commission does not find that this consensus language provides support for Ameren's RFP language. The consensus language clarifies that Ameren may request conditional approval of duplicative programs, but it does not support Ameren's vague RFP language.

The Commission will not order the IPA to remove its commentary about Ameren's bid process from the 2017 Plan, but does find that it should be re-worded to avoid use of the word "duplicity" in describing Ameren's bid process.

L. Section 9.6.5 ComEd Identification of "Performance Risk"

1. Summary

The 2017 Plan states that, in its review of programs for the 2017 Plan, ComEd distinguished between "Performance Risk," as discussed in Section 9.6.5, and "Savings Risk," as discussed in Section 9.6.6. For the terminology utilized in the 2017 Plan, performance risk is a more serious screen that could warrant the exclusion of programs from the 2017 Plan, while savings risk is less significant and not inherently a reason to consider exclusion of the program. 2017 Plan at 125.

The 2017 Plan states that in bid review discussions around program proposals for the 2017 Plan, ComEd and stakeholders developed new screening criteria for programs that could have a significant likelihood of failing to achieve savings based on past performance. This screening was manifest as a two-part test. First, as a way to identify potential "performance risk" vendors, programs were screened to determine whether the bidder submitting the program failed to deliver five percent of their savings goals from prior Section 16-111.5B programs. If a vendor was identified as failing the first test, the second screen applied was whether there was new information or a compelling reason that would suggest a different outcome for the proposed programs (e.g., new programs, new delivery approach, changes in team, or different market conditions). If the answer was "no" to both, then ComEd and stakeholders agreed the program posed a performance risk so significant that the program should not be recommended for inclusion. 2017 Plan at 125.

At the same time, while the IPA believes that risks associated with non-performance are almost entirely mitigated through pay-for-performance contracting, there are other negative outcomes caused by non-performance which may justify being mindful of performance risk. The 2017 Plan states that the two-step approach proposed as part of ComEd's submittal seeks to punish only those vendors performing especially poorly, and even then provides a second step examination that could allow for the inclusion of that vendor's program. 2017 Plan at 126.

With those considerations in mind, the IPA believes this two-step approach developed by ComEd and participating stakeholders strikes a reasonable balance between competing considerations and agrees with its application to these programs. As such, the IPA is not including these three programs pursuant to the recommendation of ComEd. 2017 Plan at 126.

2. Staff's Position

In addressing performance risk by ultimately rejecting poor performing vendors' proposed programs, the IPA identifies a two-step approach developed by ComEd and participating stakeholders which identifies potential performance risk based upon past performance, but allows for adjusted expectations based upon relevant new information. 2017 Plan at 125-126. Staff supports this two-step approach and believes it is a reasonable method to address performance risk for purposes of these specific programs in this Plan. However, Staff would like to bring to the Commission's attention several concerns with comments or assumptions made by the IPA with respect to this proposal. Staff Cmnts. at 19-20.

First, the IPA asserts the risks associated with non-performance are almost entirely mitigated through pay-for-performance contracting. 2017 Plan at 126. This overstates the protections offered by pay-for-performance contracting. In particular, pay-for-performance contracting does not allow the utilities to recover from vendors the utilities' administrative costs associated with non-performing programs. Staff Cmnts. at 20.

Additionally, the two-step proposal relies upon a five percent past performance criteria to screen bidders that may prove to be an insufficiently low benchmark in the future. For example, a provider that only delivered 6% of its savings goals certainly could not be said to have performed well in the past. Thus, Staff suggests, at a minimum, that the Commission remain open to adjustments of this approach in future years as it may prove insufficient to protect customers from costs resulting from unreasonable and/or excessive performance risk. Staff Cmnts. at 20.

Staff is also concerned that locking in such a low bar does not incent vendors to accurately forecast their expected savings. Thus, Staff respectfully requests the Commission approve this approach for purposes of the 2017 Plan, but direct the non-financially interested SAG parties to address this issue further following Commission approval in order to determine what might be an appropriate benchmark(s) to use in future years' bid review processes. Staff Cmnts. at 20-21.

3. IPA's Position

The IPA notes that Staff generally supports the two-step approach developed by ComEd and stakeholders to assess the "performance risk" of certain bids, but has concerns with the 5% past performance standard and its potential impact on future bids. Staff ultimately recommends approval of that approach for this year but requests that the Commission direct non-financially interested SAG members to address this issue (presumably via a workshop) for future Plans. The IPA agrees with this recommendation, but requests that workshops proceed with the objective that a single approach applicable to both utilities be agreed upon. IPA Resp. at 24.

4. Commission Analysis and Conclusion

The Commission approves Staff's request that the Commission approve the two-step approach for identifying potential performance risk based upon past performance for purposes of the 2017 Plan. In addition, the Commission directs the non-financially interested SAG parties to address this issue further following Commission approval in order to determine what might be an appropriate benchmark(s) to use in future years bid review processes. Moreover, the Commission agrees with the IPA that SAG should address a single approach which will be applicable to both utilities.

M. Section 9.6.8 ComEd Programs Recommended for Approval

1. Summary

The 2017 Plan states that ComEd's submittal identifies 21 energy efficiency programs for inclusion in the 2017 Plan (five managed by ComEd and 16 which are third-party administered). All of these programs passed the TRC test at the time of assessment. ComEd also provided the results of the UCT test and 14 of the 16 proposed programs passed the UCT. The 2017 Plan states that, as it has in prior years, the IPA considers the UCT to be informational only and has not used the UCT test in its consideration of which programs to include in the 2017 Plan. 2017 Plan at 127.

2. Staff's Position

Staff disagrees with the IPA's statement that the UCT is informational only. The results of the UCT are provided to satisfy the Section 16-111.5B(a)(3)(D) requirement to include an "[a]nalysis showing that the new or expanded cost-effective energy efficiency programs or measures would lead to a reduction in the overall cost of electric service." 220 ILCS 5/16-111.5B(a)(3)(D). Two of the energy efficiency programs that pass the TRC test and that the IPA proposes to be approved for implementation in the ComEd service territory fail to satisfy the UCT. Specifically, both the Middle School Energy Education Campaign Program and the Low Income Multifamily Efficiency Program ("LIMEP") have UCT values equal to 0.95. In Staff's opinion the Commission should rely upon this information that shows that approval of each of these programs would each lead to an increase in the overall cost of electric service and direct the IPA to exclude these two programs that fail the UCT from the Plan. Staff Cmnts. at 18-19.

Staff notes that the Commission stated in the *2016 Plan Docket*, that the:

> only reduction in the cost of electric service that would take place with energy efficiency programs that are more expensive than electricity would be to shift the cost of electricity onto the purchase of energy efficiency, at a greater price. Procurement of such energy efficiency programs seems to contravene the spirit, if not the letter, of this portion of the statute.

2016 Plan Docket, Order at 102. Staff opines that the Commission should also be cognizant of the large number of programs already included in the 2017 Plan and the significant administrative burden and costs these will impose. As the Commission determined in last year's *2016 Plan Docket*, the statute provides the Commission with flexibility to impose practical limits on the procurement of energy efficiency pursuant to Section 16-111.5B. *2016 Plan Docket*, Order at 100. Accordingly, Staff recommends that the Commission direct the IPA to exclude the Middle School Energy Education Campaign Program and the LIMEP, which are expected to increase the cost of electric service, from the 2017 Plan. Staff Cmnts. at 19.

Staff notes that both the IPA and ERC argue that if the TRC test ratio is greater than one, the program must be included in the plan. Staff argues that the Commission should reject IPA's and ERC's arguments because the results of the UCT are provided to satisfy the Section 16-111.5B(a)(3)(D) requirement to include an "[a]nalysis showing that the new or expanded cost-effective energy efficiency programs or measures would lead to a reduction in the overall cost of electric service." 220 ILCS 5/16-111.5B(a)(3)(D). The focus on the reduction in the cost of electric service is consistent with the standard which the Commission is required to apply to the approval of IPA Plans under the PUA. 220 ILCS 5/16-111.5(d)(4). That PUA standard being, the plan will "ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability." 220 ILCS 5/16-111.5(d)(4). Staff asserts that a program with a TRC greater than one but a UCT less than one would not meet that Section 5/16-111.5(d)(4) electric service cost requirement. For these reasons, the Commission should not include in the 2017 Plan energy efficiency programs that do not lead to a reduction in the overall cost of electric service. Staff Rep. at 9-10.

3. ERC's Position

In response to the respective RFPs from Ameren and ComEd, ERC states that it proposed to implement the LIMEP in each electric utility's service territory. ERC explains that the LIMEP is designed to provide cost-effective energy efficiency retrofits to customers residing in federally assisted housing within Illinois. The LIMEP will expand on the Illinois Public Housing Authority's Efficient Living Energy Program by providing further electrical energy savings through the installation of linear fluorescent lighting, LED lights, control systems, and HVAC equipment, as well as low-flow water fixtures in all-electric buildings. ERC Resp. at 1-2.

ERC notes that both Ameren and ComEd concluded that the LIMEP is appropriate and included it in their respective proposals to the IPA for the promotion and expansion of energy efficiency programs and measures. The IPA concurred with Ameren and ComEd in this regard and included the LIMEP in its 2017 Plan for both utilities. ERC disagrees with Staff's position that inclusion of the LIMEP for ComEd is not cost-effective under the UCT and should therefore be excluded from the 2017 Plan. ERC Resp. at 2.

ERC challenges Staff's reliance on the UCT and points out that neither the Ameren nor the ComEd RFP seeking energy efficiency programs identifies the UCT among the criteria against which proposed energy efficiency programs will be measured. Moreover, the test that the IPA uses to determine if a program is cost-effective is the TRC test, which is designed to evaluate whether the total costs of energy in the utility service territory will decrease. ERC explains that a TRC value over 1.0 indicates that the benefits exceed costs. The LIMEP has a calculated TRC value of 1.65, showing significant benefits. Notably, the TRC value for the LIMEP is higher than the TRC value calculated for eight of the 16 programs in the proposed ComEd energy efficiency offerings. 2017 Plan at 128, Table 9-5: ComEd Energy Efficiency Offerings. ERC Resp. at 3.

Additionally, ERC observes that all of the proposed Ameren energy efficiency offerings rated a UCT value greater than 1.0, including a LIMEP offering identical to the one Staff finds objectionable. ERC notes that a value of 0.95 in the ComEd service territory is very close to 1.0, and when considered in conjunction with other benefits not captured by the UCT, does not justify excluding a program that will help low income households. ERC urges the Commission to consider the fact that by reducing low income energy bills, the LIMEP: 1) makes energy more affordable for the participating low income households; 2) reduces the number of households unable to afford monthly energy payments; 3) can help to break the disconnection-reconnection cycle for many low income households; 4) reduces arrearage collection expenses and uncollectible accounts; 5) reduces or eliminates the need for energy assistance for many participating households; and 6) enables households to participate in the Low Income Home Energy Assistance Program that otherwise would not have received benefits because generally, funding for LIHEAP is insufficient for the need. Such benefits have an overall economic value to ratepayers that is not reflected in UCT results. ERC Resp. at 3-4.

4. Ameren's Position

Ameren agrees with Staff that programs which do not lead to an overall reduction in the cost of electric service should be rejected, for all of the reasons stated in Staff's Response. Ameren Rep. at 25.

5. IPA's Position

The IPA explains that whatever the policy merits of the UCT, the governing law states that the Commission "shall also approve the energy efficiency programs and measures included in the procurement plan . . . if the Commission determines they fully capture the potential for all achievable cost-effective savings, to the extent practicable." 220 ILCS 5/16-111.5B(a)(5). As a cost-effective program failing the UCT could still be "capable of being put into practice or being done or accomplished," the IPA believes that a program with a TRC test result of greater than 1 but a UCT test result of less than 1 should be approved by the Commission—especially against the backdrop of a corresponding requirement that "all achievable cost-effective savings" be "fully capture[d]." IPA Resp. at 23.

Furthermore, a determination that the UCT is provided for informational purposes only has been the IPA's approach for each prior procurement plan for which a Section 16-111.5(a)(3)(D) UCT analysis has been required (*See* 2016 Plan at 99, 2013; 2015 Plan at 76, 80; 2014 Plan at 87, 89), in addition to the 2017 Plan (*See* 2017 Plan at 121, 127). The IPA maintains that UCT results have never been considered a valid basis for barring otherwise cost-effective programs, and nothing in Staff's Comments provides a sound rationale for departing from that well-established approach. The IPA avers that the UCT is not the TRC, and the law clearly mandates that the TRC be used to assess the costs and benefits of proposed energy efficiency programs in determining fitness for approval in the IPA's Plan. IPA Resp. at 23-24.

6. Commission Analysis and Conclusion

Staff proposes that ERC's LIMEP program be excluded from the 2017 Plan because its UCT score is 0.95, just below the 1.0 score necessary for a program to reduce the overall cost of electricity. The LIMEP program scored a 1.65 on the TRC test. The Commission notes, again, the applicable statutory language regarding the Commission's role in approving energy efficiency programs. It states:

> the Commission shall also approve the energy efficiency programs and measures included in the procurement plan, including the annual energy savings goal, if the Commission determines they fully capture the potential for all achievable cost-effective savings, to the extent practicable, and otherwise satisfy the requirements of Section 8-103 of this Act.

220 ILCS 5/16-111.5B(a)(5). In general, therefore, the Commission must approve cost-effective programs, i.e., those that pass the TRC. The Commission has found that it has some discretion in the approval of energy efficiency programs based upon the qualifier "to the extent practicable" which is included in the statutory language. With this understanding, the Commission cannot adopt Staff's position which seems to propose a bright line test based on the UCT and would essentially ignore the results of the TRC.

It is clear to the Commission that ERC's LIMEP program will provide many benefits, which are not captured in the UCT test. The Commission notes that this program is designed to lower the bills of low income households, which will reduce the number of households that are unable to make monthly energy payments and thereby reduce the utility's uncollectible expense. For these reasons, the Commission finds that this cost-effective program should be included in the 2017 Plan.

Although the bidder of the Middle School Energy Education project did not intervene in this proceeding, the Commission notes that its TRC score was even higher than the LIMEP at 1.78 and it had the same 0.95 UCT score. No further discussion was provided by the parties regarding this program, and the Commission will not remove this cost-effective program from the 2017 Plan either.

VI. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having reviewed the entire record, is of the opinion and finds that:

(1) Commonwealth Edison Company, Ameren Illinois Company d/b/a Ameren Illinois and MidAmerican Energy Company are corporations engaged in the retail sale and delivery of electricity to the public in Illinois, and each is a "public utility" as defined in Section 3-105 of the Public Utilities Act and an "electric utility" as defined in Section 16-102 of the Public Utilities Act;

(2) the Commission has jurisdiction over the parties hereto and the subject matter hereof;

(3) the recital of fact and conclusions of law in the prefatory portion of this Order are supported by the record and are hereby adopted as findings of fact and conclusions of law;

(4) the load forecast for Ameren Illinois Company d/b/a Ameren Illinois attached to the Illinois Power Agency's September 27, 2016 petition should be approved; the load forecast for Commonwealth Edison Company attached to the Illinois Power Agency's September 27, 2016 petition should be approved; the load forecast for MidAmerican Energy Company attached to the Illinois Power Agency’s September 27, 2016 petition should be approved;

(5) subject to the modifications adopted in the prefatory portion of this Order, including such recommendations and objections as are approved above, the 2017 Plan filed by the Illinois Power Agency pursuant to Section 16-111.5 of the Public Utilities Act should be approved; as modified, the 2017 Plan, and load forecasts found appropriate above, will ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability; in making this finding, the Commission is not expressing its concurrence in every statement or opinion contained in the 2017 Plan and no presumptions are created with respect thereto; and

(6) all motions, petitions, objections, and other matters in this proceeding which remain unresolved should be disposed of consistent with the conclusions herein.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that subject to the modifications adopted in the prefatory portion of this Order, the 2017 Plan filed by the Illinois Power Agency pursuant to Section 16-111.5 of the Public Utilities Act is hereby approved, as are the load forecasts found appropriate above.

IT IS FURTHER ORDERED that all motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that, subject to Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

DATED:	November 14, 2016
BRIEFS ON EXCEPTIONS DUE:	November 21, 2016
REPLY BRIEFS ON EXCEPTIONS DUE:	December 2, 2016

Leslie Haynes,
Administrative Law Judge